

# **Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control**

## **Semi-Annual Technical Progress Report**

**October 1, 2000 – March 31, 2001**

**Cooperative Agreement No: DE-FC26-99FT40718**

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## **Abstract**

This document summarizes progress on Cooperative Agreement DE-FC26-99FT40718, Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control, during the time period October 1, 2000 through March 31, 2001. The objective of this project is to demonstrate the use of alkaline reagents injected into the furnace of coal-fired boilers as a means of controlling sulfuric acid emissions. The coincident removal of hydrochloric acid and hydrofluoric acid will also be determined, as will the removal of arsenic, a known poison for NO<sub>x</sub> selective catalytic reduction (SCR) catalysts. EPRI, the Tennessee Valley Authority (TVA), First Energy Corporation, and the Dravo Lime Company are project co-funders. URS Corporation is the prime contractor.

This is the third reporting period for the subject Cooperative Agreement. During this period, the three short-term sorbent injection tests were conducted on Unit 3 of First Energy's Bruce Mansfield Plant. These tests determined the effectiveness of injecting alkaline slurries into the upper furnace of the boiler as a means of controlling sulfuric acid emissions from this unit. The alkaline slurries tested included pressure-hydrated dolomitic lime, commercially available magnesium hydroxide slurry, and a byproduct magnesium hydroxide slurry. The tests showed that injecting either the commercial or the byproduct magnesium hydroxide slurry could achieve greater than 90% sulfuric acid removal. Balance of plant impacts, primarily on the electrostatic precipitator particulate control device, were also determined. These results are presented and discussed in this report.

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## 1.0 INTRODUCTION

This document is the semi-annual Technical Progress Report for the project “Furnace Injection of Alkaline Sorbents for Sulfuric Acid Control,” for the time period October 1, 2000 through March 31, 2001. The objective of this project is to demonstrate the use of alkaline reagents injected into the furnace of coal-fired boilers as a means of controlling sulfuric acid emissions. The coincident removal of hydrochloric acid and hydrofluoric acid is also being determined, as will the removal of arsenic, a known poison for NO<sub>x</sub> selective catalytic reduction (SCR) catalysts. The project is being funded by the U.S. DOE National Energy Technology Laboratory under Cooperative Agreement DE-FC26-99FT40718. EPRI, the Tennessee Valley Authority (TVA), First Energy Corporation, and the Dravo Lime Company are project co-funders. URS Corporation (formerly Radian International) is the prime contractor.

Sulfuric acid is present in most flue gases from coal combustion because a small percentage of the SO<sub>2</sub> produced from the sulfur in the coal (approximately 0.5 to 1.5%) is further oxidized to form SO<sub>3</sub>. The SO<sub>3</sub> combines with flue gas moisture to form vapor-phase or condensed sulfuric acid at temperatures below 500°F.

Besides being a Toxic Release Inventory substance and a potential precursor to acid aerosol/condensable emissions from coal-fired boilers, sulfuric acid in the flue gas can lead to boiler air heater plugging and fouling, corrosion in the air heater and downstream, and the formation of a visible plume. These issues will likely be exacerbated with the retrofit of SCR for NO<sub>x</sub> control on some coal-fired plants, as SCR catalysts are known to further oxidize a portion of the flue gas SO<sub>2</sub> to SO<sub>3</sub>.

The project is testing the effectiveness of furnace injection of four different calcium- and/or magnesium-based alkaline sorbents on full-scale utility boilers. These reagents have been tested during four one- to two-week tests conducted on two First Energy Bruce Mansfield Plant (BMP) units. One of the sorbents tested was produced from a wet flue gas desulfurization (FGD) system waste stream, at a system that employs the Thioclear<sup>®</sup> scrubbing process. The other three sorbents are commercially available.

After completing the four one- to two-week tests, the most promising sorbent has been selected for longer-term (up to 30-day) full-scale tests. The longer-term tests will be used to confirm the effectiveness of the sorbent tested over extended operation, and to determine balance-of-plant impacts. Two longer-term tests will be conducted, one on a First Energy unit and the second on a TVA unit.

At the completion of the project, it is expected that sufficient full-scale test data will be available to design and implement commercial installations of the sulfuric acid control technologies demonstrated.

The remainder of this report is divided into three sections. Section 2 provides a summary account of progress on the project during the current reporting period, including any problems encountered. Section 3 provides a forecast of plans for the next and future reporting periods, and Section 4 provides a detailed discussion of technical results from the project during the current reporting period.



## **2.0 PROGRESS DURING THE CURRENT REPORTING PERIOD**

### **2.1 Summary of Progress**

The current reporting period, October 1, 2000 through March 31, 2001, is the third technical progress reporting period for this project. October 1, 1999 was the start date for this Cooperative Agreement.

In early October of 2000, considerable efforts went towards completing the assembly and startup of the sorbent slurry injection equipment used to conduct furnace slurry injection tests. Figure 2-1 illustrates the slurry injection system. Major equipment items in the system include two 10,000 gallon slurry storage tanks, two air-driven slurry transfer pumps, a day tank installed just below the slurry injection level, two slurry injection pumps, two magnetic flow meters for measuring injection rates, and slurry agitators for the three tanks. The two air-driven pumps are on loan from team-member TVA, but the other items were purchased for this project. Other equipment items include tank level transmitters, pressure indicators and switches, air regulators and solenoid valves, solid-state controllers, pump skids, hoses, data acquisition equipment, and miscellaneous electrical components, pipe fittings, ball valves, and wiring. The system was started up the weeks of October 9 and October 16. As described below, some revisions were required to allow successful operation during the first sorbent slurry injection test, which began the week of October 23, 2000.

Also during the current period, a baseline test and the final three of four planned short-term sorbent injection tests were conducted at BMP on Unit 3. All three short-term tests involved the injection of sorbent slurries into the upper furnace on half of the boiler (the east side). The first slurry injection test was conducted the weeks of October 23 and October 30, and evaluated the effectiveness of pressure hydrated dolomitic lime injected into the upper furnace at lowering flue gas  $\text{SO}_3$  concentrations. The second test was conducted with a commercially available magnesium hydroxide slurry as the reagent, the weeks of November 27 and December 4, 2000. The third test was conducted with byproduct magnesium hydroxide slurry injected into the upper furnace, the weeks of February 12 and February 19, 2001. The baseline test (no sorbent injection) on Unit 3 was conducted the week of October 2, 2000.

The primary measure of the success of the slurry injection tests was the reduction in flue gas  $\text{SO}_3$  concentration at the electrostatic precipitator (ESP) outlet on the side of the boiler receiving the slurry injection. Some  $\text{SO}_3$  concentration measurements were also made at the air

heater inlet and outlet locations. Balance of plant impacts from the sorbent injection were also determined, primarily effects on ESP operation.

After each test was complete, samples collected during the test were chemically analyzed, and data collected were organized, reduced and analyzed. Results from this testing are presented in Section 4 of this Technical Report.

Two subcontracts were completed during the current reporting period. In one subcontract, CT&E conducted fly ash resistivity measurements during baseline and sorbent injection conditions as part of the short-term test evaluations. In the other subcontract, moving the sorbent injection location required the use of different nozzles to assure adequate spray coverage. Ashworth Engineering designed slurry nozzles for injecting at the new location, and a machine shop in Ohio fabricated the new nozzles. The pressure hydrated dolomitic lime and commercial magnesium hydroxide sorbent slurries were injected at the 11<sup>th</sup> floor of the boiler structure, on the front wall directly across from the nose of the boiler. Midway through the byproduct magnesium hydroxide test, the injection location was moved higher in the boiler, to the 14<sup>th</sup> floor, on the front wall across from the pendant superheater sections. This move required the new nozzles.

## **2.2 Problems Encountered**

As might be expected, a variety of problems were encountered during start-up, operation and testing of the full-scale sorbent slurry injection system. These problems and their eventual resolution are described below.

Most problems with the slurry injection system were related to the extremely high viscosity of the first sorbent, a pressure-hydrated dolomitic lime slurry at 60 wt% solids. The viscosity of this material was estimated to be over 1000 centipoise. First, the air-driven diaphragm slurry transfer pumps were not able to deliver the slurry to the day tank, which was located on the 9<sup>th</sup> floor of the boiler structure at an elevation about 150 ft above the pumps. With the higher than expected viscosity, the high density of the material, and a pump design pressure limitation of 125 psig on the motive air to the pumps, they just could not generate enough discharge head. The solution to this problem was to dilute the slurry to 35 wt%, so both the density and viscosity were lowered.

Even with this change, the air-driven slurry transfer pumps remained problematic throughout the three short-term tests. The slurry flow requirements lie at the “top left” quadrant

of the pump curves (maximum head, low flow) rather than falling in the ideal range at the middle of the curve. The pumps are prone to freezing, as the compressed air at the host plant is relatively wet, and the moisture in the air freezes as the air expands from 125 psig to atmospheric pressure. This freezing stops the pump until it thaws, or an operator manually cycles the air supply to the pump to break the frozen air valve loose. For future testing the pumps have been upgraded to a reportedly “freeze proof” air valve design.

Nearly all of the flexible hoses used to route slurries from the 10,000 gallon storage tanks to the day tank, and from the day tank to the injection lances, have had to be replaced with larger-diameter hose. This upgrading has been required for two reasons: the quantities of reagent required to achieve greater than 90% SO<sub>3</sub> removal have been greater than originally expected, and the viscosities of the sorbent slurries have been higher than expected. The original hose sizes were generally based on slurry velocities in the range of 6 to 8 ft/sec and assumed slurry injection rate requirements; the upgraded hoses and piping are now sized for less than 5 ft/sec and higher slurry rates than were anticipated in the original design.

Level control in the day tank has been somewhat problematic. Originally the plan was to provide a gravity overflow line back to the 10,000-gallon storage tanks. With over 150 ft of elevation difference, there was plenty of head available to finance the gravity return flow. However, the viscous slurries would not flow well enough into the overflow line to establish a siphon, and the tank would overflow unless service water was first used to establish a siphon. With a full atmosphere of suction available once the siphon was established, the tank level would quickly drain down to below the overflow, breaking the siphon and starting the cycle over again. This problem was resolved by using a completely different approach for controlling tank level. The tank ultrasonic level indicator and relays were used to start and stop the air supply to the air-driven slurry transfer pumps, to maintain the day tank level within a desired range. On two occasions the day tank overflowed because the ultrasonic level transmitter became covered with splashed up slurry, and no longer provided an accurate level indication for the control relays. This tendency has been corrected in two ways: first, a downspout was installed inside the tank to direct the slurry feed to below the slurry level, eliminating splashing, and second, a float switch was installed near the top of the tank that will automatically shut down the air-driven transfer pump if a high-level situation is encountered, even if the level indicator fails to function properly.

The net effect of the freezing problem with the air-driven transfer pumps and the day tank level control issues, as described above, is that the injection equipment requires more operator attention than was originally planned. This has typically required an extra URS person on site

during the short-term tests to provide 20 to 24 hours of injection equipment monitoring daily, rather than the planned 10 to 12 hours that one person could provide.

There have been some problems with the short-term tests from the standpoint of host unit operations, as well. BMP Unit 3 can operate at nearly full load with only three of four ESPs and ID fans in service. While testing with sorbent slurry injection in one-half of the unit, operation with only three of four ID fans in service was found to adversely affect sorbent distribution on the half of the boiler being treated. Once this problem was identified, subsequent testing has been conducted with all four fans in service whenever possible.

For the byproduct magnesium hydroxide test, the variability of the coal supply to BMP Unit 3 has confounded test results. Coal quality, particularly sulfur content, varied more than we would have liked, making it difficult to determine what the uncontrolled SO<sub>3</sub> emissions might have been at any particular time, and therefore difficult to quantify an SO<sub>3</sub> removal percentage. The results of daily coal samples are being used to account for these variations, although one grab sample each day most likely does not adequately address the true variation in coal quality throughout each day.

## **3.0 PLANS FOR FUTURE REPORTING PERIODS**

### **3.1 Plans for Next Reporting Period**

The next reporting period covers the time period April 1, 2001 through September 30, 2001. The long-term test at BMP Unit 3 is now scheduled to begin May 11 and end June 4. The test is being held to 25 rather than 30 days due to budget constraints. Baseline sampling for the long-term test is scheduled to begin May 8. The long-term test will be conducted with byproduct magnesium hydroxide as the reagent.

Also during the next reporting period, two technical notes will be prepared. One technical note will present results from a baseline and three short-term slurry injection tests, and the second will present the results from the long-term test at BMP.

### **3.2 Prospects for Future Progress**

The subsequent reporting period would be October 1, 2001 through March 31, 2002. However, this period extends beyond the current period of performance of this Cooperative Agreement, which ends June 30, 2001. An extension of the period of performance through March 31, 2002 has been requested.

The long-term sorbent injection test at a TVA plant is currently scheduled to begin sometime in October 2001. Later in that reporting period, the data reduction and reporting for the TVA long-term test will be completed, as will a final report for this project.

## 4.0 TECHNICAL RESULTS

The technical results for the current reporting period (October 1, 2000 through March 31, 2001) are for three short-term (approximately two-week) alkaline slurry injection tests conducted on BMP Unit 3, to investigate the effectiveness of alkaline sorbents for sulfuric acid control. The tests also evaluated the effects of these sorbents on boiler equipment performance. The first short-term test was conducted in the previous reporting period, and investigated the effect of injecting dry dolomite powder ( $\text{CaCO}_3 \bullet \text{MgCO}_3$ ), a mineral similar to limestone, into the furnace of Unit 2.

The three tests conducted during the current period evaluated pressure-hydrated dolomitic lime [ $\text{Ca}(\text{OH})_2 \bullet \text{Mg}(\text{OH})_2$ ] (PHDL), commercially available magnesium hydroxide [ $\text{Mg}(\text{OH})_2$ ] (commercial Mg) and a byproduct magnesium hydroxide (byproduct Mg) as furnace injection sorbents for  $\text{SO}_3$  control.

### 4.1 Test Description

During the test program, alkaline slurry sorbents were injected into one half of the Unit 3 boiler for up to two weeks, to assess their effectiveness for flue gas  $\text{SO}_3$  control. Various analytical techniques were used to assess the effects of sorbent injection. These primarily included sampling with the Controlled Condensation System (CCS) method for determining flue gas  $\text{SO}_3$  content and, to a lesser extent, an acid dew-point (ADP) meter for determining the sulfuric acid dew point (and, indirectly, the concentration of sulfuric acid) of the flue gas. Daily average  $\text{SO}_2$  concentration measurements were also made coincident with the CCS measurements. EPA Reference Method 26a was used for determining hydrochloric acid (HCl) and hydrofluoric acid (HF), as well as chlorine ( $\text{Cl}_2$ ) and fluorine ( $\text{F}_2$ ) concentrations in the flue gas. Fly ash resistivity was measured using a Wahlco resistivity probe, and impacts on ESP operation were quantified by taking voltage and current data on operating electrical sections of the Unit 3 ESP's. Sorbent and ESP hopper samples were analyzed for calcium and/or magnesium content by acid dissolution followed by atomic absorption analysis. Sorbent samples were also analyzed for density and weight percent solids by gravimetric analysis, and for total alkalinity by acid-base titration. Coal samples were collected and analyzed for a variety of parameters according to ASTM protocols. Finally, visual observations were made of boiler furnace and convective pass surfaces prior to and during sorbent injection, to observe any trends related to slag formation.

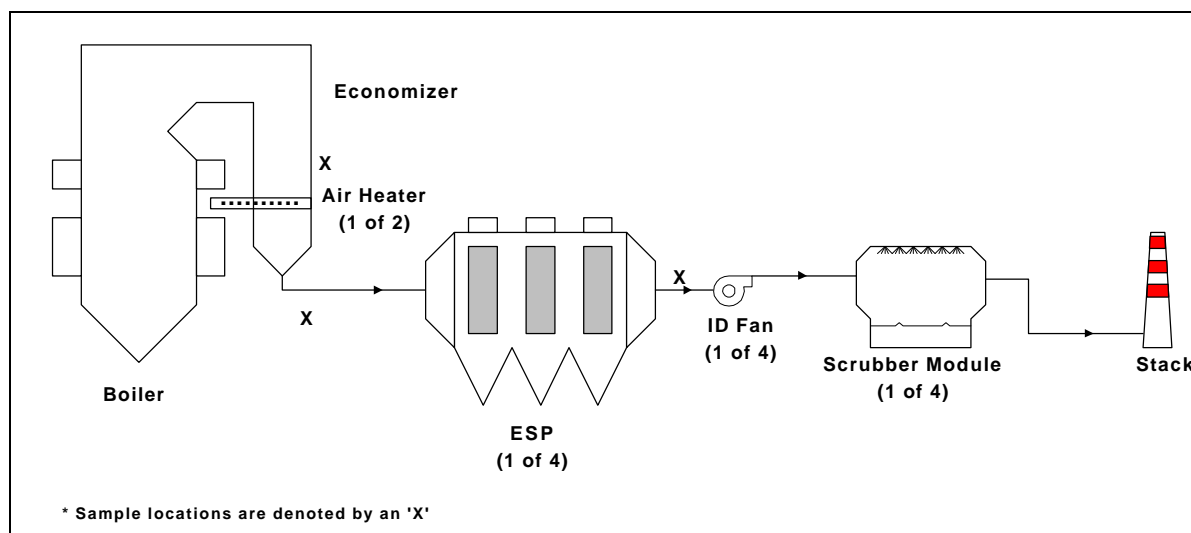
Unit 3 is rated at 800 net MW. It has an opposed-wall fired, supercritical boiler rated at approximately 6,415,000 pounds of steam per hour at 3785 psig and 1005°F/1005°F superheat and reheat temperatures. The boiler has 16 burners located on the front and back walls of the furnace. The burners are arranged in four horizontal rows on each wall, with four burners per row. One ball mill pulverizer provides the pulverized fuel for each row. Depending on fuel quality and mill condition, full load can generally be achieved with six of the eight mills in operation (and thus six of eight rows of burners in service).

Unit 3 typically burns a 4% sulfur coal. Coal blends are typically fired, predominantly blends of a McElroy coal. The actual coal sulfur can vary over a range from 2.0 to 4.5%. The facility also has permission to burn up to 20% of the fuel as petroleum coke. During the period of this study on Unit 2, a standard coal blend averaging about 4% sulfur was typically fired, although during the byproduct magnesium hydroxide test a small amount of petroleum coke was reportedly blended with a lower sulfur coal for a portion of that test.

Unit 3 was brought into service in 1980. The 800-net-MW unit operates as a swing unit to meet the load demands of the grid. During most of the short-term tests, Unit 3 operated at 750 to 850 MW gross load during daylight hours, and 550 to 650 MW overnight. The boiler is equipped with two air heaters following the economizer section. The average flue gas temperature at the outlet of the air heaters is controlled to about 300°F due to acid dew point considerations.

Figure 4-1 illustrates the flue gas path for Unit 3, and notes the gas sampling locations used during this test. Flue gas from each of the two air heaters splits into two duct runs, each of which goes to an electrostatic precipitator (ESP) followed by an induced draft (ID) fan. There are no ties between the four ducts (two per air heater) so when an ID fan is out of service, there is no gas flow through the associated air heater outlet duct and ESP. Correspondingly, the gas flow through the air heater on that side of the boiler is also reduced. Downstream of the ID fans, the flue gas flows to a common plenum, then the gas flow splits to up to five horizontal-gas-flow, flue gas desulfurization system absorber modules (four normally operate at full load). The scrubbers use a magnesium-enhanced, Thiosorbic<sup>®</sup> lime slurry reagent and produce a calcium sulfite hemihydrate ( $\text{CaSO}_3 \cdot \frac{1}{2}\text{H}_2\text{O}$ ) byproduct. The flue gas then goes to a dedicated stack for Unit 3. The flue gas in the stack is saturated at a temperature of about 130°F; no reheat is employed.

During these tests, injection of sorbent slurries was accomplished through up to six air-atomizing nozzles inserted through inspection port openings on the front wall of the boiler.



**Figure 4-1. Illustration of Flue Gas Path for BMP Unit 3**

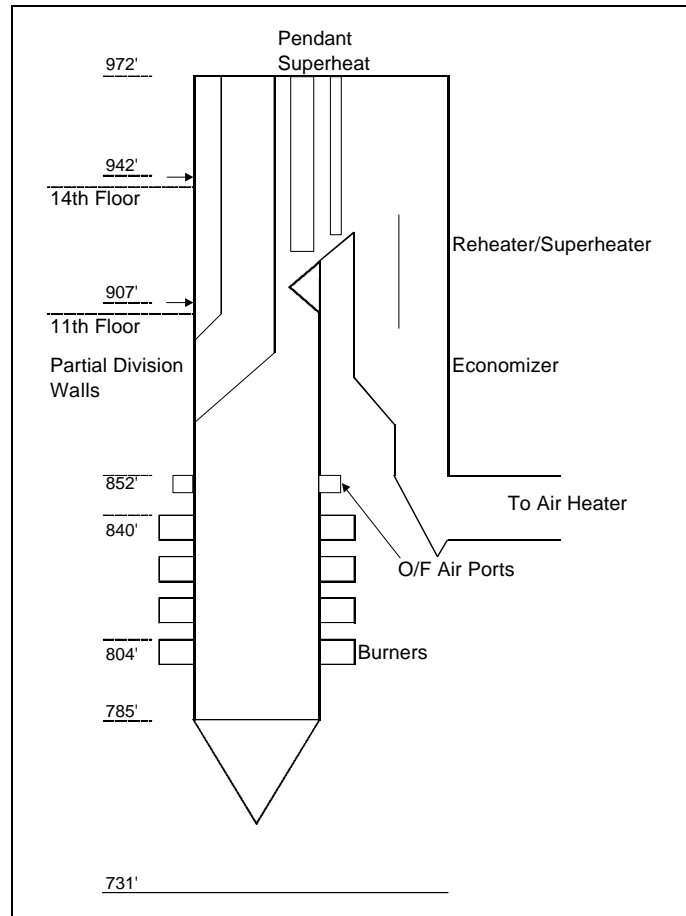
During the PHDL and commercial Mg test, the slurry was fed through ports located at the 11<sup>th</sup> floor of the boiler structure, approximately across from the “nose” of the boiler. Midway through the byproduct Mg test, the injection location was elevated to the 14<sup>th</sup> floor of the boiler structure, across from the pendant superheat platens. The injection levels, denoted by arrows, are illustrated in Figure 4-2.

At either level, the slurry injection lances were inserted through up to six upper furnace inspection ports on the east half of the boiler. At both the 11<sup>th</sup> and 14<sup>th</sup> floor, there are twelve ports across the face of the boiler. There is a port adjacent to each corner of the boiler along the front wall, then the remaining ports are situated on either side of five partial division walls that are equally spaced across the upper furnace cavity. Figure 4-3 illustrates the six lance locations on the east half of the boiler. Note that on the 14<sup>th</sup> floor, lance location No. 5 was blocked by a camera installed at that inspection port. When injecting at the 14<sup>th</sup> floor, the slurry flow that would normally have been split among six nozzles was instead fed to only five.

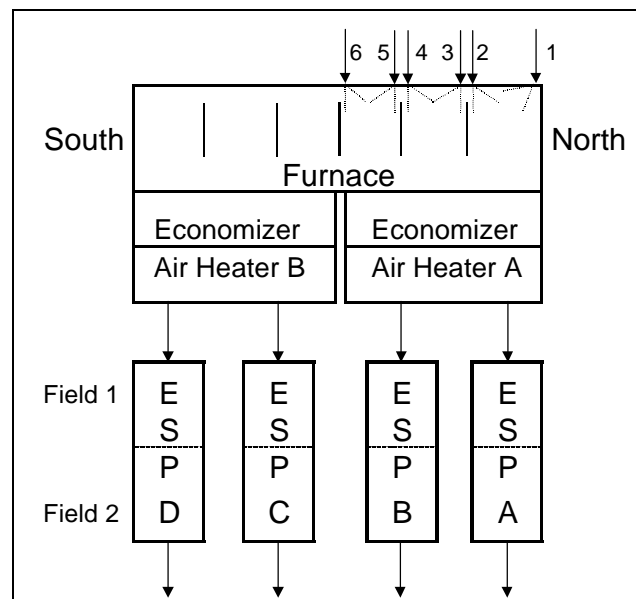
The air-atomizing nozzles were designed by Ashworth Engineering specifically for this application. The proprietary design employs an internal mix configuration, and was designed for relatively low airflow requirements and to achieve a relatively large minimum passage diameter. The air pressure to the nozzles was typically 80 psig, although in some testing the pressure was varied to quantify its effect on SO<sub>3</sub> control performance.

The sorbents injected into the furnace were delivered to the site in truckload quantities, as slurries containing 15 to 60 wt% solids, depending on the reagent. Two 10,000-gallon slurry





**Figure 4-2. Illustration of Slurry Injection Levels**



**Figure 4-3. Illustration of Slurry Injection Locations – Plan View**

storage tanks were situated in the basement of Unit 3. The tanker trucks unloaded into one or both of these tanks. Between the two tanks, approximately 4 to 5 truckloads could be stored on site. From the storage tanks, one of two air-driven diaphragm pumps was used to transfer slurry up to a 1000-gallon “day” tank located on the 9<sup>th</sup> floor of the boiler structure. The day tank level

was controlled by a signal from an ultrasonic level indicator on the day tank. Relays controlled by this signal energized (opened) a solenoid valve on the air supply to the transfer pump on low day tank level, and closed the solenoid valve on high level.

From the day tank, one or two Moyno progressing cavity pumps were used to feed slurry to the injection nozzles. The Moyno pumps were equipped with magnetic flow meters at their discharge, and pump speed was modulated to maintain slurry flow rate at a set point. The slurry flow rate set point was adjusted by the URS operator according to the density and purity of the reagent, the Unit 3 load, the expected Unit 3 coal sulfur content, and the desired reagent-to-SO<sub>3</sub> molar ratio. Slurry from the Moyno pumps was fed to a manifold, which in turn distributed slurry to the five or six operating injection nozzles. Plant compressed air was connected to each lance individually, through flexible plant air hoses.

Figure 4-3, mentioned above, also illustrates the arrangement of the four ESP’s relative to the two air heaters. Note that, because of the direction of rotation of the regenerative-type air heaters, the flue gas going to the outboard ESPs (labeled “A” and “D” in Figure 4-3) tends to be cooler and have a lower SO<sub>3</sub> content than the flue gas going to the inboard ESP’s (labeled “B” and “C”). However, no attempt was made to bias the sorbent slurry flow to the nozzles on the inboard side of the east air heater to account for this observed stratification. It was felt that the stratification was caused by the drop in gas temperature across the air heater, and was not reflective of stratification in flue gas SO<sub>3</sub> content in the furnace, where the sorbent was injected.

#### **4.1.1 Unit 3 Operating Conditions**

Testing was conducted on Unit 3 during four discrete time periods. Baseline (no sorbent injection) measurements were conducted on October 3 through 6, 2000. PHDL testing was conducted October 17 through November 1, commercial Mg testing was conducted November 28 through December 8, and byproduct Mg testing was conducted February 13 through February 22, 2001. Unit 3 operating conditions during these test periods are summarized in Table 4-1.

**Table 4-1. Unit 3 Operating Conditions during Baseline and Short-term Sorbent Injection Tests**

Date	Time Period for Testing	Average Unit Load (gross MW)	Average Economizer Exit O <sub>2</sub> (%)	Coal Mills Out of Service	ID Fans Out of Service
<b>Baseline Testing</b>					
10/3/00	15:00-19:00	782	3.3	D	NA*
10/4/00	10:00-17:00	788	3.3	D	NA
10/5/00	10:00-16:00	796	3.2	D	NA
10/6/00	10:00-15:00	851	3.2	D	NA
<b>PHDL Testing</b>					
10/17/00	13:00-18:00	NA	NA	NA	NA
10/18/00	09:00-13:00	798	3.4	D, F	NA
10/20/00	10:00-16:00	791	3.3	D, F	NA
10/23/00	11:00-17:00	NA	NA	NA	NA
10/24/00	09:00-17:00	825	3.5	D	NA
10/25/00	09:00-11:00	870	3.6	D	NA
10/26/00	02:00-05:00	560	5.0	A, D, F	NA
11/1/00	01:00-05:00	631	4.5	A, D	NA
<b>Commercial Mg Testing</b>					
11/28/00	11:00-20:00	785	3.6	G	-
11/29/00	11:00-13:00	785	3.4	D, F	-
11/30/00	01:00-04:00	549	4.9	A, C, D	D
12/1/00	10:00-17:00	788	3.4	D	D
12/4/00	10:00-16:00	757	3.7	-	D
12/5/00	10:00-16:00	826	3.7	D	-
12/6/00	09:00-15:00	813	4.1	D	-
12/7/00	11:00-18:00	785	3.2	D	-
12/8/00	09:00-11:00	816	3.1	H	-
<b>Byproduct Mg Testing</b>					
2/13/01	09:00-15:00	726	4.6	A, C, D	NA
2/14/01	07:00-16:00	669	4.2	A, D	C, A
2/15/01	09:00-15:00	766	4.6	A, D	A
2/16/01	09:00-15:00	773	4.2	D	A
2/19/01	09:00-16:00	807	3.8	D	-
2/20/01	09:00-12:00	802	4.0	D	-
2/21/01	09:00-13:00	791	4.0	D	-
2/22/01	09:00-13:00	800	4.6	A, D	-

\*NA – data not available

The times listed in the table are periods when flue gas characterization testing was conducted on Unit 3. Flue gas SO<sub>3</sub> concentrations by the CCS method were the primary measure of sorbent performance. Flue gas characterization tests were typically conducted during daytime hours each test day, although there were periods during the PHDL and commercial Mg tests

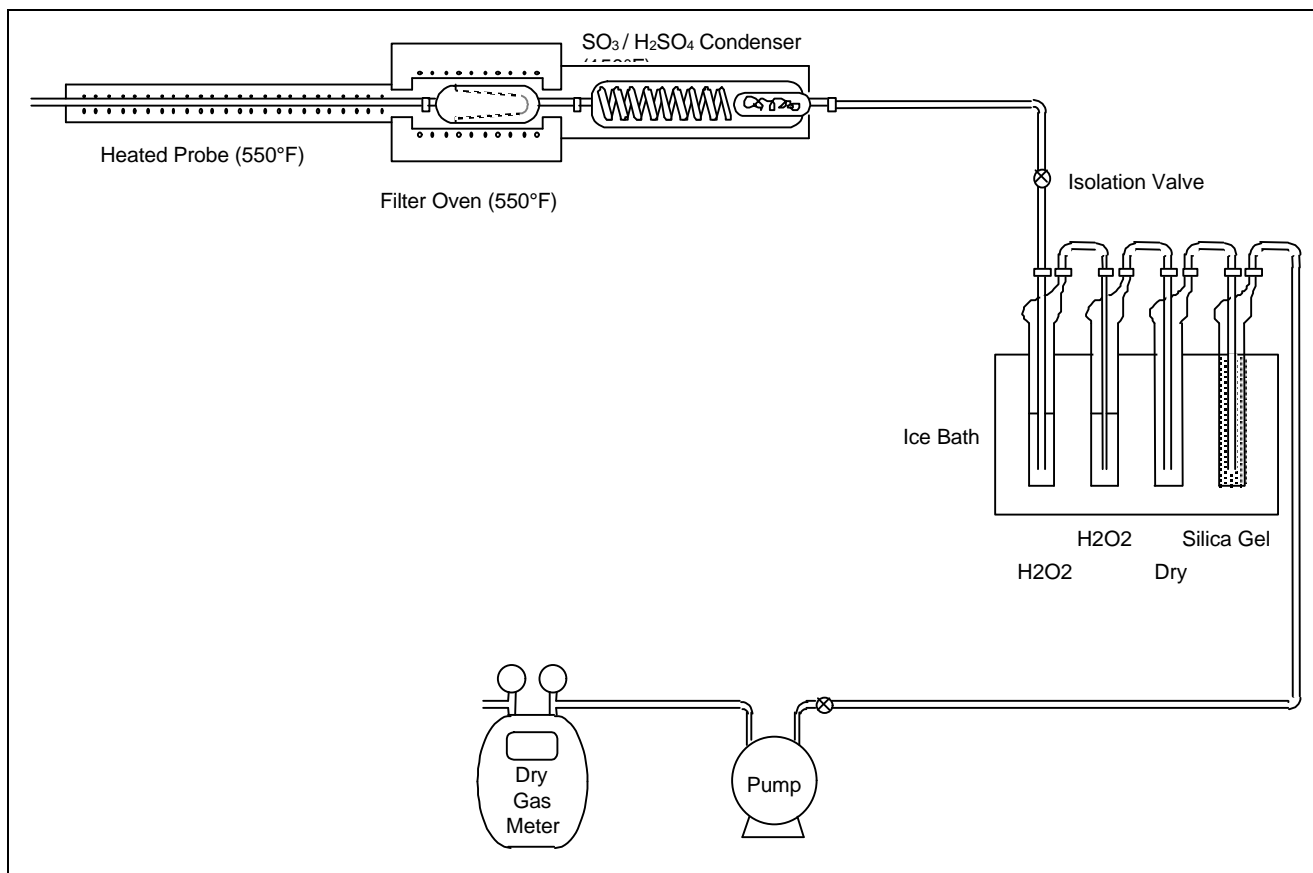
where sampling was conducted very early in the morning, between 1:00 a.m. and 5:00 a.m. These early morning tests were conducted for two reasons: 1). Testing overnight while the unit was at low load allowed testing at higher sorbent-to-SO<sub>3</sub> mole ratios than could be achieved at full load, and 2). Testing at low load presumably lowered furnace temperatures at the point of sorbent injection. This effect is discussed further below.

During most flue gas testing, the steam generator was at close to full load with one to two pulverizers and burner rows out of service. Most frequently, the “D” pulverizer was out of service, which correspondingly takes the top row of burners on the back side of the furnace out of service. Average loads during daytime test periods were typically in the range of 800 gross MW  $\pm$  50 MW. One exception was during the first week of the byproduct Mg test, when coal quality and slagging concerns caused the unit load to be limited to around 700 MW  $\pm$  50 MW. Overnight the boiler load was often reduced. In most cases overnight loads were reduced into the range of 550 gross MW to 650 gross MW, although in some instances the load remained above 700 MW overnight due to grid demand. During sorbent injection tests the sorbent injection rate was typically reduced in direct proportion to unit load. An exception was during the overnight flue gas testing periods, when the sorbent injection rates were maintained at maximum rates achievable to allow operation at a high sorbent-to-SO<sub>3</sub> mole ratios

#### **4.1.2 Test Methods**

H<sub>2</sub>SO<sub>4</sub> Vapor by Controlled Condensation. Sulfuric acid vapor concentrations were measured at the economizer outlet, air heater outlet, and ESP outlet using the controlled condensation system (CCS). A diagram of this sulfuric acid vapor train is shown in Figure 4-4. Controlled condensation is generally regarded as the most accurate method for measuring sulfuric acid vapor concentrations in flue gas, particularly where the flue gas is above the acid dew point. For these units, this would include flue gas temperatures above about 280°F, or all locations upstream of the FGD system.

In the controlled condensation system, a sample of flue gas is pulled from the duct through a heated, quartz-lined probe. Particulate material is removed from the sample using a quartz thimble filter. Both the probe and the filter are maintained at about 550°F to ensure that no sulfuric acid vapor condenses in this part of the sampling system. Next, the filtered flue gas sample passes to a glass condenser that is maintained at a temperature of about 150°F by a circulating water bath. This temperature is well below the acid dew point but above the water dew point. The only material in most flue gases that will condense at this temperature is sulfuric acid vapor. Other acid gases have dew points that are much nearer the water dew point. At the



**Figure 4-4. Controlled Condensation Sulfuric Acid Vapor Train**

completion of a CCS run, the condenser is removed from the sampling system, and a rinse of the condenser is analyzed for sulfate content. By measuring the total volume of flue gas pulled through the system and the amount of sulfate in the condenser, the concentration of H<sub>2</sub>SO<sub>4</sub> vapor in the flue gas can be calculated.

Acid Dew Point. During some tests, a portable acid dew-point meter manufactured by Land Combustion was used to determine the acid dew point. These measurements were made at the inlet ducts to the ESPs where the flue gas temperature is in the range of 280°F to 340°F. The acid dew-point measurement can be used to estimate the flue gas content of sulfuric acid. There are several relationships correlating acid dew point to flue gas sulfuric acid concentration, such as those by Verhoff and Banchero.<sup>1</sup> Acid dew-point correlations from different sources are not always in agreement, often yielding results considerably different, especially at high dew points and/or high sulfuric acid concentrations. Acid dew-point measurements were used primarily as

an indicator of sorbent effectiveness, but not directly to quantify performance. Consequently the acid dew-point measurement data are not reported herein.

Method 26a—Hydrogen Halide and Halogen Emissions (chloride and fluoride). Method 26a is the reference EPA test method for determining hydrogen halide and halogen emissions—hydrochloric and hydrofluoric acids, chlorine and fluorine. This method requires isokinetic sample extraction with an apparatus similar to that used in EPA Method 5. An illustration of the Method 26a train is shown in Figure 4-5. Method 26a is different from Method 5 in that it includes an impinger containing sulfuric acid and an impinger containing sodium hydroxide. With the Method 26a sampling train, a flue gas sample is extracted isokinetically, passes through a heated probe and through a particulate filter contained in a heated oven. Following the particulate filter, the gas sample passes through the impinger train where moisture is removed in the first impinger, hydrogen halides (HCl and HF) are dissolved in the second impinger which contains sulfuric acid, and halogens (Cl<sub>2</sub> and F<sub>2</sub>) are dissolved in the third impinger which contains sodium hydroxide. The samples collected are analyzed by ion chromatography (IC) or ion specific electrode.

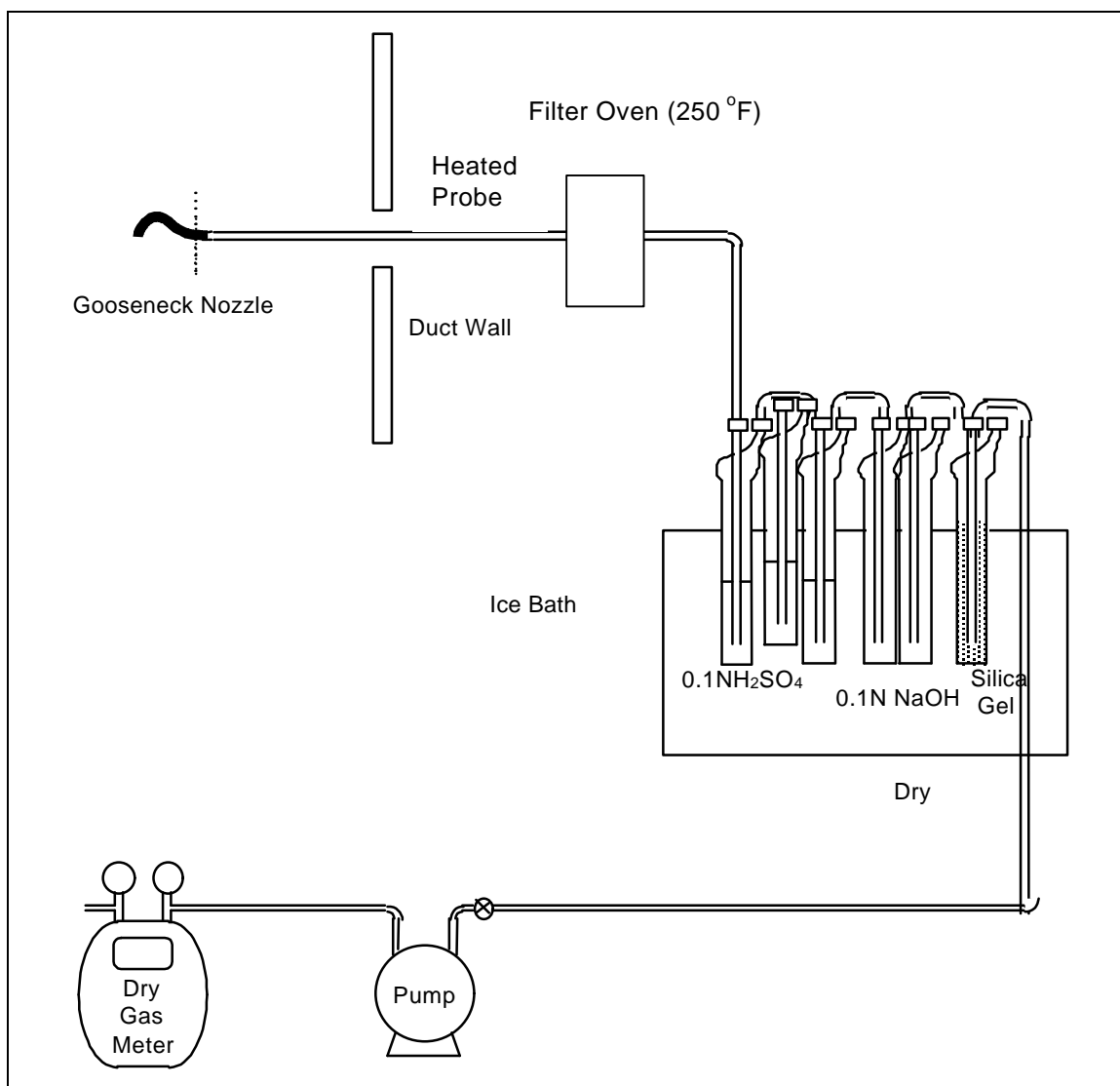
Fly Ash Resistivity. Fly ash resistivity was determined using a Wahlco in-situ probe. The sampling for fly ash resistivity was conducted at the economizer exit. The resistivity probe and its operator were provided by subcontractor Commercial Testing and Engineering, out of their Wellington, Ohio source testing office.

## **4.2 Results**

Results from the four-day test are presented and discussed in the following section. First, the results of the baseline tests are presented and discussed, then results which quantify the impacts of sorbent injection on Unit 3 sulfuric acid concentrations are discussed for each of the three sorbents. Finally, balance-of-plant issues are discussed, including impacts of sorbent injection on fly ash resistivity and ESP performance. Because these data were not collected for all three sorbent tests, balance-of-plant issues are discussed in a separate subsection, for all tests where such data were collected.

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<sup>1</sup> Pierce, Robert R., “Estimating Acid Dewpoints in Stack Gases,” *Chemical Engineering*, April 11, 1977, pp 125-128.



**Figure 4-5. EPA Method 5/Method 26a Sampling Train**

#### **4.2.1 Baseline Test Results**

As described earlier, baseline data were collected during four days early in October 2000. The primary objectives of these measurements was to measure baseline (no sorbent injection) SO<sub>3</sub> concentrations at a variety of measurement locations, but additional sampling was conducted for flue gas SO<sub>2</sub>, HCl, HF and halogen gas concentrations, and ESP outlet particulate concentrations.

Table 4-2 summarizes the results of CCS measurements made at various locations throughout the flue gas path on Unit 3. Please refer to Figures 4-1 through 4-3 to review how

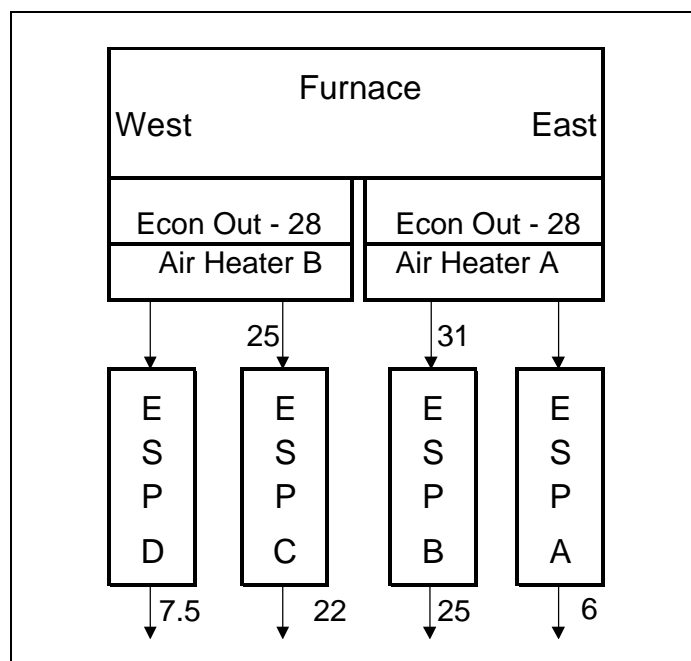
**Table 4-2. Summary of Flue Gas SO<sub>3</sub> Concentrations Measured for Unit 3 Baseline Testing**

Date	Measured SO <sub>3</sub> Concentration, ppmv (dry basis)				
	Run 1	Run 2	Run 3	Run 4	Average
<b>Economizer A Outlet:</b>					
10/3/00	27	24	28	-	26
10/4/00	25	35	26	30	30
<b>Economizer B Outlet:</b>					
10/4/00	22	29	28	32	28
<b>ESP B Inlet/Air Heater A Outlet (Hot Side):</b>					
10/5/00	39	29	26	31	31
<b>ESP C Inlet/Air Heater B Outlet (Hot Side):</b>					
10/5/00	24	23	27	24	25
<b>ESP A Outlet:</b>					
10/3/00	5.0	5.6	5.2	-	5.3
10/4/00	6.6	7.5	7.1	-	7.0
10/5/00	5.6	6.0	5.7	5.0	5.6
10/6/00	-	6.6	6.6	-	6.6
<b>ESP B Outlet:</b>					
10/4/00	28	25	27	26	27
10/5/00	25	20	26	-	24
10/6/00	21	24	24	-	23
<b>ESP C Outlet:</b>					
10/6/00	22	26	18	-	22
<b>ESP D Outlet:</b>					
10/6/00	7.9	6.3	8.4	-	7.5

these sample locations are laid out in the gas path. Table 4-2 shows the results of individual measurement runs by date and by location. Figure 4-6 summarizes these same data by location, showing the average of all measurements made at a particular location irrespective of sampling date or number of runs.

When plotted as averages in Figure 4-6, the results show no significant side-to-side variation in SO<sub>3</sub> conversion in the furnace and back pass of the boiler, and little or no SO<sub>3</sub> removal across the air heaters on their “hot” sides (11% or less). SO<sub>3</sub> does not appear to be removed across the “B” and “C” ESP’s at a high percentage either; on average the removal percentage across these two ESP’s varies from 11 to 20%. The sampling ports for the outlet of the “cold” side of the air heaters and inlets to the “A” and “D” ESP’s is difficult to access on Unit 3, therefore no CCS measurements were made at those locations. However, comparing the economizer outlet values to the concentrations measured at the outlets of the “A” and “D” ESP’s, a total of 73 to 79% reduction in SO<sub>3</sub> concentration is seen. Most of this reduction is presumed to occur across the air heater. Note that the measured concentration averages of 6.0 and 7.5





**Figure 4-6. Summary of Baseline CCS Measurements at BMP Unit 3**

correspond with acid dew-point values of approximately 263°F and 267°F, respectively. These acid dew point values are consistent with temperatures that might be expected on the “cold” side of an air heater that is averaging approximately 305°F for an outlet gas temperature. Because of the observed stratification of SO<sub>3</sub> concentrations between the ESP’s, it was decided to conduct most of the CCS measurements during the sorbent injection tests on the “B” or “C” ESP inlet and outlet, where most of the flue gas SO<sub>3</sub> content is seen.

Throughout this report, SO<sub>3</sub> removal during sorbent injection is reported as the percent reduction in SO<sub>3</sub> concentration as measured at the B ESP outlet, for injection versus baseline conditions. It would be possible to calculate a higher percentage by comparing baseline economizer outlet values to ESP outlet values during sorbent injection. However, the latter calculation would overstate the effect of reagent injection, because it would also incorporate the removal across the air heater and ESP that is already seen at baseline (no injection) conditions.

The economizer outlet SO<sub>3</sub> concentration data in Table 4-2 were used to calculate an average SO<sub>2</sub> to SO<sub>3</sub> conversion percentage for Unit 3, and served as a basis for setting sorbent injection rates and for reporting sorbent-to-SO<sub>3</sub> molar ratios. During the baseline testing, two Unit 3 coal feed samples were collected and analyzed, on October 4 and October 6. The ultimate analyses of these coal samples are shown in Table 4-3.

**Table 4-3. Ultimate Analyses of Coal Samples from the Unit 3 Baseline Test**

Parameter	Composition, wt% (except as noted)	
	Sample from 10/4/00	Sample from 10/6/00
Carbon	66.69	68.72
Hydrogen	4.56	4.67
Nitrogen	1.18	1.21
Sulfur	4.10	4.01
Chlorine (ppm)	534	616
Oxygen	4.43	4.40
Moisture	5.77	5.50
Ash	13.22	11.43
Total	100.00	100.00
HHV (Btu/lb)	12,495	12,195

These results were used in combustion calculations to calculate the total amount of SO<sub>2</sub> that would be produced from the combustion of these coals, then that value was compared to the measured economizer outlet SO<sub>3</sub> concentrations. The calculated conversion percentage was 0.9%, which is near the middle of the expected range for bituminous coals in pulverized-coal-fired boilers (approximately 0.5 to 1.5%). This conversion percentage can be affected by many variables, including excess air levels in the furnace, slag accumulations on heat transfer surfaces, etc. Consequently, it was decided to use a “round number” of 1% as the average value for conversion of SO<sub>2</sub> to SO<sub>3</sub> in the Unit 3 boiler for calculating sorbent-to-SO<sub>3</sub> mole ratios for the short-term slurry injection tests. However, it is recognized that the actual percentage at any given time could vary because of the influences of excess air levels and other factors.

#### **4.2.2 PHDL Sorbent Injection Test Results**

The PHDL slurry tests were conducted the last two weeks in October 2000. The PHDL slurry was purchased from Clear<sub>2</sub>O Technologies. They purchase PHDL powder from Gen Lime in central Ohio and prepare it as a 60 wt% aqueous slurry for use in water treating applications. The 60 wt% slurry proved to be more viscous than the temporary slurry injection equipment on Unit 3 could handle, so for this testing Clear<sub>2</sub>O produced a more dilute slurry at 35 wt%. This material was injected as a slurry rather than as a powder for several reasons. First, the other sorbents tested were available only as slurries, so testing the PHDL as a slurry allowed the same equipment to be used. The other reason is that the momentum transfer available when injecting relatively dense slurry droplets into a large furnace, including the mass associated with the water, can lead to better sorbent particle penetration into the furnace than if the material was injected as a dry powder.

The PHDL slurry solids were measured to have a mass mean particle diameter in the range of 7 to 8 microns, and a specific surface area (by BET analysis) of 19 m<sup>2</sup>/g. Both of these values are in the range of what might be measured for a high-calcium, atmospheric-hydrated lime.

Table 4-4 summarizes the data collected during the PHDL testing. The calcium plus magnesium alkali-to-SO<sub>3</sub> molar ratio is calculated from the sulfur content of the coal samples collected during these tests, and an assumed 1% conversion of SO<sub>2</sub> to SO<sub>3</sub>. This factor was described above. There is some evidence that the magnesium hydroxide content of the PHDL is more reactive with flue gas SO<sub>3</sub> than the calcium hydroxide content, so perhaps the Mg:SO<sub>3</sub> molar ratio is a better metric for performance. The values in the table for (Ca + Mg):SO<sub>3</sub> ratio can be divided by two to get the Mg:SO<sub>3</sub> mole ratio. The slurry flow rate in the table is the total to all six nozzles; the flow rate to each individual nozzle was nominally one-sixth the value shown.

These same data are plotted versus time in Figure 4-7 for the first week, and Figure 4-8 for the second week of testing. The reader is referred to both the tabulated and graphical presentations of data in the following discussions.

**Table 4-4. Flue Gas SO<sub>3</sub> Concentration and Slurry Injection Rate Data for the PHDL Test**

Date/Time	Unit Load, gross MW	Injection Rate, gpm total	(Ca+Mg): SO <sub>3</sub> Mole Ratio	Measured SO <sub>3</sub> Concentration (ppmv, dry basis)		
				Air Heater Outlet/ ESP B Inlet	ESP B Outlet	ESP C Outlet
10/17/00 13:50	NA*	0	0	-	19	-
10/17/00 14:47	NA	0	0	-	20	26
10/17/00 15:10	NA	0	0	-	18	24
10/17/00 15:52	NA	0	0	-	-	26
<i>Average</i>					19	25
10/18/00 9:38	807	0	0	42	-	-
10/18/00 9:52	807	0	0	44	24	-
10/18/00 10:30	820	0	0	35	21	-
10/18/00 11:03	820	0	0	-	25	28
10/18/00 11:45	791	0	0	-	-	32
10/18/00 12:23	774	0	0	-	-	38
<i>Average</i>				40	24	32
10/20/00 13:55	801	10.2	4.6	28	11	15
10/20/00 14:12	801	10.2	4.6	43	-	13
10/20/00 15:00	788	10.2	4.7	53	11	13
<i>Average</i>				41	11	14
10/23/00 11:57	NA	0	0	29	27	13
10/23/00 13:14	NA	0	0	30	29	14
10/23/00 13:52	NA	0	0	34	25	23
10/23/00 14:28	NA	0	0	29	22	-
<i>Average</i>				30	25.7	17
10/24/00 9:57	807	10.2	4.2	24	-	22
10/24/00 10:30	857	10.2	4.2	26	-	24
10/24/00 10:47	857	10.2	4.2	28	12	30
10/24/00 11:54	852	10.2	4.2	25	18	-
10/24/00 12:42	861	10.2	4.2	-	20	-
10/24/00 13:42	842	10.2	4.2	-	23	-
10/24/00 14:33	766	10.2	4.2	-	19	-
10/24/00 15:22	789	10.2	4.2	-	22	-
<i>Average</i>				26	19	25
10/25/00 9:00	867	10.2	4.1	35	19	46
10/25/00 9:42	874	10.2	4.1	37	-	29
<i>Average</i>				36	19	37
10/26/00 2:04	560	8.0	4.9	27	16	26
10/26/00 2:38	560	0**	0**	28	15	24
10/26/00 3:10	560	4.4	2.7	23	14	28
10/26/00 3:45	559	13.3	8.2	6.4	14	26
10/26/00 4:45	585	13.3	8.2	21	40	-

Table 4-4. (Continued)

Date/Time	Unit Load, gross MW	Injection Rate, gpm total	(Ca+Mg): SO <sub>3</sub> Mole Ratio	Measured SO <sub>3</sub> Concentration (ppmv, dry basis)		
				Air Heater Outlet/ ESP B Inlet	ESP B Outlet	ESP C Outlet
11/1/00 1:48	560	16	9.8	23.6	18	17
11/1/00 2:27	561	20	12	24.1	17	17
11/1/00 3:09	561	12	7.3	24.6	17	19
11/1/00 4:00	561	12	7.3	27.5	20	19
11/1/00 4:46	606	12	6.6	27.2	20	21

\*NA – Data not available.

\*\*Temporary interruption in the slurry injection

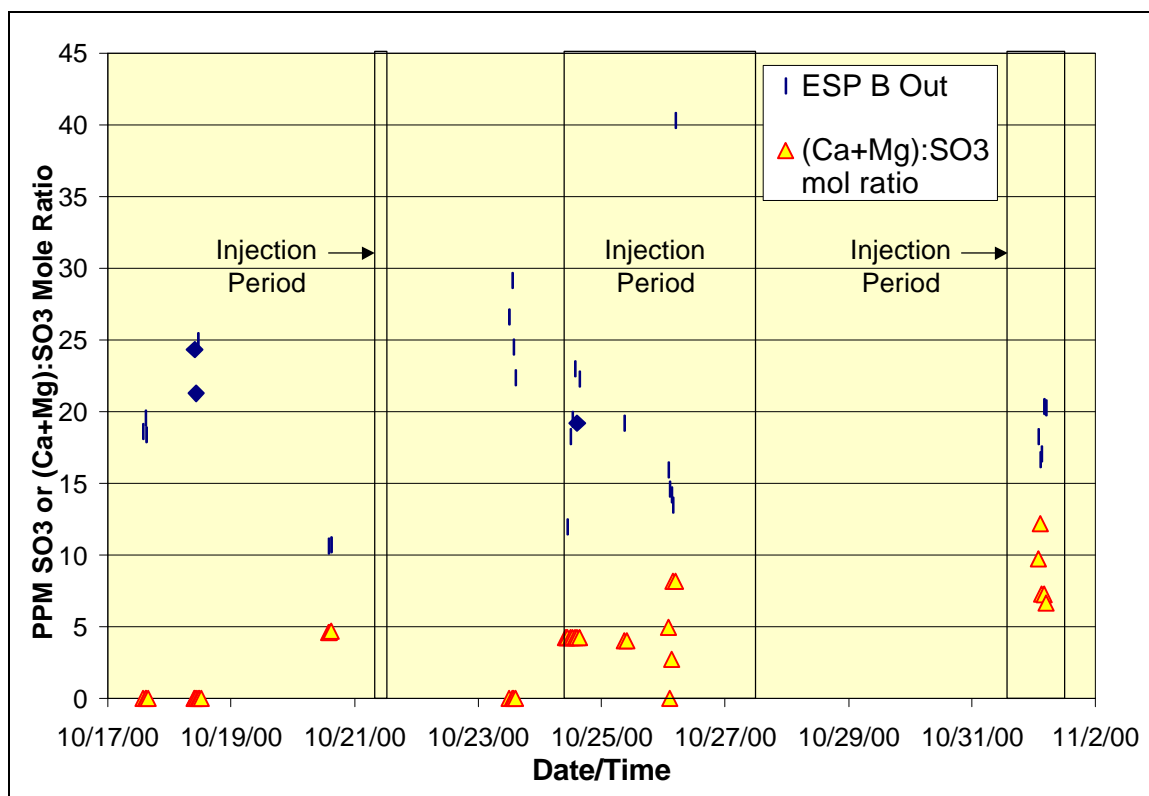
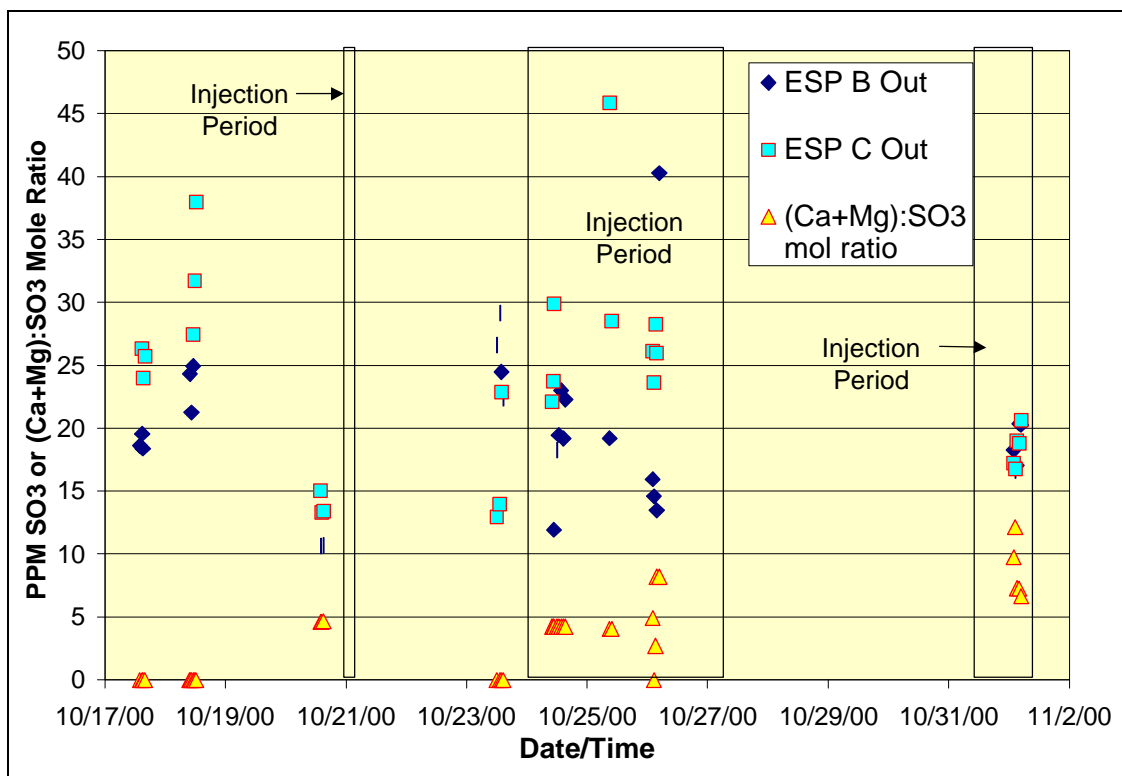


Figure 4-7. Results from the First Week of the PHDL Test



**Figure 4-8. Results from the Second Week of the PHDL Test**

Note that the ESP C outlet concentration shown in the table and in the figures is on the side of the boiler not being injected, so this was assumed to represent an “uncontrolled” SO<sub>3</sub> concentration. However, as will be discussed later in this technical note, there is evidence that the alkaline slurries being injected on the east side of the furnace were migrating to the west side and influencing SO<sub>3</sub> concentrations being measured on the ESP C outlet. This effect was particularly evident when only three of the four ID fans and ESP’s were operating, most notably when the “D” fan was out of service.

The data in Table 4-4 for calcium plus magnesium alkali-to-SO<sub>3</sub> molar ratios are based on the amount of alkali in the sorbent slurry injected compared to one-half of the coal feed rate times the coal sulfur content, using the 1% factor for SO<sub>2</sub> to SO<sub>3</sub> conversion. Ultimate analysis data for coal samples collected during the PHDL test, which were used in these calculations, are shown in Table 4-5.

Table 4-4 does not show percentage SO<sub>3</sub> removals for the PHDL injection periods, primarily because there is some question as to what the uncontrolled concentrations might have been at the ESP B outlet. It was hoped that the ESP C outlet concentrations would provide a

**Table 4-5. Ultimate Analyses of Coal Samples from the Unit 3 PHDL Test**

Parameter	Composition, wt% (except as noted)							
	10/17	10/18	10/20	10/23	10/25	10/26	10/30	11/1
Carbon	68.87	68.89	66.80	68.66	65.79	67.00	64.66	65.89
Hydrogen	4.39	4.44	4.22	4.19	3.97	4.01	3.77	3.92
Nitrogen	1.27	1.22	1.22	1.26	1.17	1.22	1.19	1.24
Sulfur	3.57	3.99	4.04	4.37	4.56	4.03	4.07	4.18
Chlorine (ppm)	466	527	684	549	477	610	547	540
Oxygen	4.67	4.57	5.06	4.84	4.90	4.77	4.76	4.94
Moisture	4.19	5.43	5.84	4.53	5.57	5.86	7.05	6.01
Ash	12.99	11.41	12.75	12.10	13.99	13.05	14.45	13.77
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV (Btu/lb)	12,301	12,347	12,049	12,364	11,866	11,766	11,662	11,854

good comparison for uncontrolled concentrations, but as discussed below, this did not turn out to be a good assumption due to carryover of injected material to the other side of the boiler. As can be seen in Table 4-5, the coal sulfur content varied somewhat over the test period, with most samples ranging from about 4 to 4.5% sulfur.

Because the PHDL test was the first slurry injection test conducted, the sorbent injection equipment was also being started up and undergoing shake-down testing. As such, sorbent injection started and stopped a couple of times during the test. This allowed additional opportunities to collect baseline (no injection) SO<sub>3</sub> concentration data.

Comparing the baseline data for October 18 with injection data from October 20, it appears that up to 54% SO<sub>3</sub> removal was realized at the ESP B outlet, for slurry injection at a (Ca + Mg):SO<sub>3</sub> molar ratio of about 4.6:1. However, this level of performance was not seen again in subsequent testing. Comparing baseline values for October 23 to injection results for the next two days, it appears that only 26% removal was achieved at an only slightly lower (Ca + Mg):SO<sub>3</sub> ratio of 4.2:1.

For the next two days of data in the table, the tests were conducted in the early morning hours, while the unit was at low load. Daily averages are not shown in the table because of the varied injection rates on those days. The data from the morning of October 26 showed that only about 47% removal was achieved (assuming at 25 to 26 ppm baseline) when injecting PHDL at a relatively high (Ca + Mg):SO<sub>3</sub> ratio of 8.2:1. This ignores the very high reading for ESP B outlet concentration in the second measurement at the 13.3 gpm slurry injection rate.

At this point, the observed SO<sub>3</sub> removal was nowhere near the target value of 90% or higher when injecting PHDL at the then-current flow rate limit of the injection system, even at

lower unit load. There was some expectation that SO<sub>3</sub> removal would improve with time, due to “boiler conditioning” with the buildup of alkali solids on heat transfer surfaces, but it was presumed that this effect would not improve SO<sub>3</sub> removal from less than 50% to over 90%. Consequently, it was decided to shut down over the weekend to de-bottleneck the slurry injection rate capability with minor piping changes.

The testing on November 1 represented a last attempt to achieve higher SO<sub>3</sub> removal percentages with the injection of PHDL. The maximum slurry flow rate achievable was about 20 gpm, but this was only for a relatively short period, as 20 gpm exceeded the ability of the air-driven slurry transfer pumps to maintain level in the day tank. The unit load was as low overnight on November 1 as it had been on October 26. A short-term test (about one hour) at a (Ca + Mg):SO<sub>3</sub> ratio of about 12:1 saw only about 35% SO<sub>3</sub> removal, based on an assumed baseline value of 25-26 ppm at the ESP B outlet. Although the test at this injection rate lasted less than one hour, slurry injection had been running at a relatively high rate for about 12 hours prior to these measurements. Continued operation at a (Ca + Mg):SO<sub>3</sub> ratio of about 7:1 saw only about 25% SO<sub>3</sub> removal based on the assumed baseline value.

This overnight test also provided the first evidence of significant solids crossover to the west side of the boiler under some injection conditions. The ESP C outlet values were measured to be almost equal to those at the ESP B outlet, and appeared to track with the slurry injection rate.

Although the true baseline SO<sub>3</sub> concentrations for these low load tests are not known and the removal percentages are approximate, it is clear that PHDL slurry injection at the rates tested was not able to lower ESP B outlet SO<sub>3</sub> concentrations to the desired range of less than 5 ppm. At this point it was decided to suspend PHDL testing. There were a few remaining issues associated with the PHDL tests, such as whether good slurry distribution into the boiler was being achieved, and whether or not the furnace gas temperature was too high at the 11<sup>th</sup> floor location. However, based on the SO<sub>3</sub> removal percentages generally being at 50% or less, and the measured ESP B outlet SO<sub>3</sub> concentrations remaining above 10 ppm, it was decided to test another reagent to see if higher percentages could be achieved with the current injection configuration.

The issue of furnace gas temperature at the point of sorbent injection was discussed by the project team at length. There was concern that the furnace gas temperature at the point of sorbent injection was too high, and was causing sorbent dead burning. If the sorbent is injected at an ideal calcining temperature, the water represented by the hydroxides evolves from the



particles, leaving porous, high-surface area calcium and magnesium oxides available to react with furnace gas  $\text{SO}_3$ . If the temperature is too high, though, these oxides sinter, or nearly melt, producing dense, non-porous particles that are relatively unreactive.

There was disagreement among project team members as to whether this should be an issue or not. One school of thought was that the injection of the sorbents as a slurry, and as a hydroxide that would endothermically calcine, would tend to protect the particles from sintering. Others speculated that the evaporation and calcining would occur too rapidly to be much help.

Others thought that the whole issue was moot. There are only two locations where sorbents could be injected into the upper furnace or even the back pass without extensive waterwall modifications, the 11<sup>th</sup> floor or 14<sup>th</sup> floor inspection ports. It was estimated that the furnace gas temperature at the 14<sup>th</sup> floor location was about the same at full load as at the 11<sup>th</sup> floor at reduced load. If a sorbent was not effective when injected at the 11<sup>th</sup> floor at reduced load (e.g., 560 MW as on October 26 and November 1), it could not be expected to be effective at full unit load even if the injection location were moved to the 14<sup>th</sup> floor.

To provide more data to support these discussions, after the PHDL test was completed First Energy conducted furnace gas temperature measurements with high velocity thermocouple (HVT) probes at these locations. The results of these measurements are summarized in Table 4-6.

**Table 4-6. Furnace Gas Temperature Measurements on Unit 3 Boiler at Full and Reduced Load**

Inspection Port Level	Unit Load (net MW)	Furnace Gas Temperature (°F)		
		Inspection Port 1*	Inspection Port 3*	Inspection Port 4*
11 <sup>th</sup> Floor	780	2233	2338	2074
11 <sup>th</sup> Floor	500	2089	2157	1987
14 <sup>th</sup> Floor	780	1935	1864	1875

\*Refer to Figure 4-2 for inspection port numbering; all measurements made 15 ft into the 40-ft furnace depth

The results in Table 4-6 showed several things about the furnace gas temperature at the 11<sup>th</sup> floor injection location. First, at full load, the temperatures were a bit higher than was assumed to be ideal based on furnace sorbent injection research for  $\text{SO}_2$  control 15 to 20 years ago. That research generally showed a temperature in the range of 2000°F to 2200°F to be ideal to provide adequate mixing and reaction time, but minimize sintering. At low load, the temperatures were observed to be lowered into a more acceptable range, though. The second

observation is that the 14<sup>th</sup> floor temperatures were 100°F to 300°F lower at full load than the 11<sup>th</sup> floor temperatures at low load. If temperature were critical to sorbent reactivity in this range of furnace gas temperatures, these data show that the 14<sup>th</sup> floor location might provide more favorable results.

#### **4.2.3 Commercial Mg Sorbent Injection Test Results**

The second short-term slurry injection test was originally planned to be a high-calcium (Thiosorbic<sup>®</sup>) slaked lime, which is prepared on site as a 15 wt% slurry for the FGD reagent. This was seen as being a relatively low-cost reagent that was already available on site, and hence a potentially attractive option for furnace injection for SO<sub>3</sub> control. However, based on the relatively poor performance of the PHDL in the first test, it was decided to test more of a “known SO<sub>3</sub> control, commercially available magnesium hydroxide. Magnesium hydroxide and magnesium oxide have been widely used as fuel or furnace additives to control SO<sub>3</sub> formation in oil-fired applications, and to a lesser extent have been used to control SO<sub>3</sub> in coal-fired applications. (Note that the rate controlling mechanisms for SO<sub>3</sub> formation in coal-fired applications are believed to be different than those for oil firing.) The literature does not report any previous application of magnesium hydroxide injection on a coal-fired boiler to achieve the target SO<sub>3</sub> removal for this project (greater than 90% removal), though.

The magnesium hydroxide selected for this test is produced by Martin Marietta Magnesia Specialties in their Manistee, Michigan plant (the alliteration was unavoidable by the author). That material is precipitated from magnesium chloride, which reportedly produces a finer particle size than the other common route to producing magnesium hydroxide – pressure slaking magnesium oxide. The precipitated material is produced as a 60 wt% aqueous slurry. The mass mean diameter of the particles in the precipitated material is in the range of 5 to 6 microns, and the BET surface area is in the range of 11 to 16 m<sup>2</sup>/g. As was the PHDL, the viscosity and density of this material at 60 wt% solids was too high to be handled at the anticipated injection rates by the existing temporary injection system. Consequently, this material was diluted to 30 wt% solids with plant service water as it was unloaded into the 10,000-gallon slurry storage tanks, and injected at 30 wt%.

The commercial Mg test was conducted in the first part of December 2000. The results of this test are summarized in Table 4-7, and illustrated in Figures 4-9 (week one) and 4-10 (week two). The Mg:SO<sub>3</sub> ratios shown in the table and figures are based on the magnesium hydroxide content of the slurry injected compared to one-half of the coal feed rate times the coal sulfur content, using the 1% factor for SO<sub>2</sub> to SO<sub>3</sub> conversion. Ultimate analysis data for coal samples

**Table 4-7. Flue Gas SO<sub>3</sub> Concentration and Slurry Injection Rate Data  
for the Commercial Mg Test**

Date/Time	Unit Load, gross MW	Injection Rate, gpm total	Mg:SO <sub>3</sub> Molar Ratio	Measured SO <sub>3</sub> Concentration, ppmv dry basis		
				Air Heater Outlet/ ESP B Inlet	ESP B Outlet	ESP C Outlet
11/28/00 11:46	834	0	0	23	21	29
11/28/00 12:40	779	0	0	23	18	30
11/28/00 14:14	791	0	0	22	18	30
<i>Average</i>				22	19	30
11/28/00 18:56	775	6.3	4.8	-	17	22
11/28/00 19:29	775	6.3	4.9	-	18	-
<i>Average</i>					17	
11/29/00 10:58	780	6.3	5.5	15	11	29
11/29/00 11:39	790	6.3	5.4	17	11	30
<i>Average</i>				16	11	30
11/29/00 12:32	790	0	0	28	20	28
11/30/00 1:18	548	10	11	18	10	18
11/30/00 2:05	548	10	11	17	9.3	17
11/30/00 2:56	549	17	19	14	5.0	12
11/30/00 3:51	549	17	19	11	3.6	12
12/1/00 10:20	780	6.3	5.3	24	17	23
12/1/00 10:57	780	6.3	5.3	27	18	22
12/1/00 12:37	773	6.3	5.4	28	19**	21
12/1/00 13:12	773	6.3	5.4	29	20**	26
		0*		---		
12/1/00 15:38	777	6.3	5.3	31	20***	23
12/1/00 16:13	777	6.3	5.3	38	21***	25
12/4/00 9:59	768	6.3	5.4	21	15	23
12/4/00 10:54	767	6.3	5.4	28	19	22
12/4/00 12:18	762	10	8.6	22	15	21
12/4/00 12:53	753	10	8.7	25	14	19
12/4/00 14:32	775	17	14	22	10	19
12/4/00 15:10	775	17	14	21	9.4	20
12/5/00 10:03	824	6.3	4.7	18	7.1	31
12/5/00 10:36	824	6.3	4.8	15	9.3	31
12/5/00 12:24	822	6.3	4.8	17	12**	31

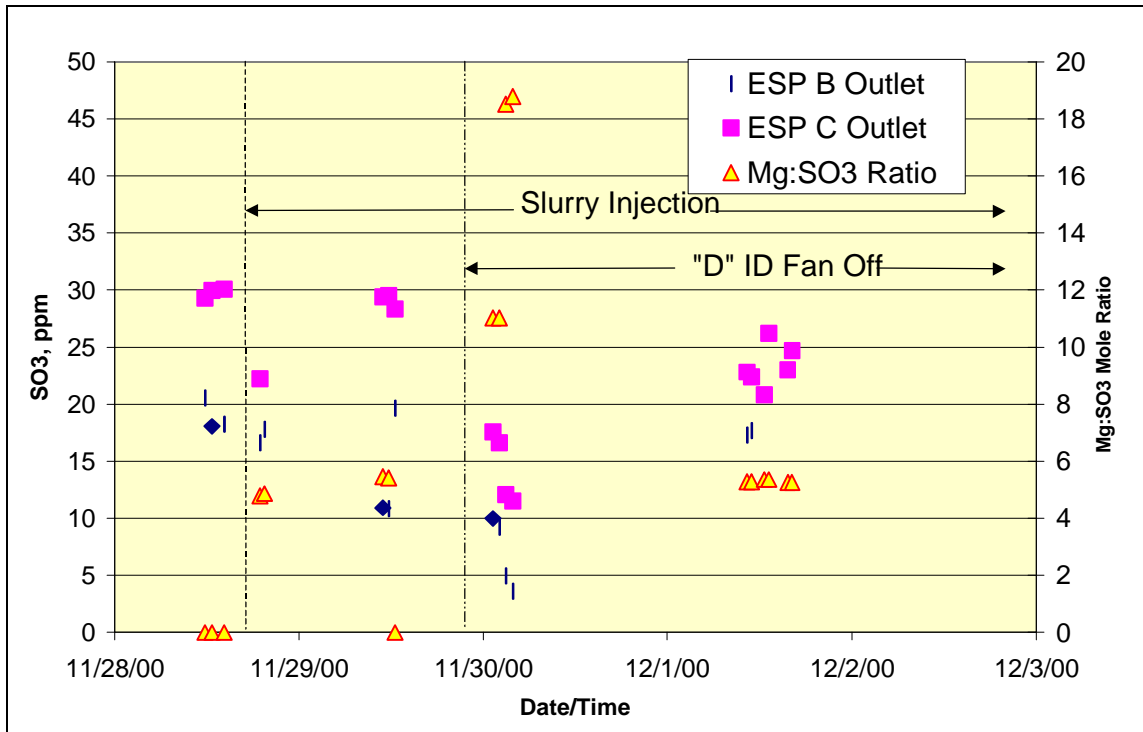
**Table 4-7. (Continued)**

Date/Time	Unit Load, gross MW	Injection Rate, gpm total	Mg:SO <sub>3</sub> Molar Ratio	Measured SO <sub>3</sub> Concentration, ppmv dry basis		
				Air Heater Outlet/ ESP B Inlet	ESP B Outlet	ESP C Outlet
12/5/00 12:58	828	6.3	4.7	22	13**	35
12/5/00 14:36	836	6.3	4.7	20	13***	35
12/5/00 15:11	836	6.3	4.7	25	14***	36
12/6/00 9:35	817	6.3	5.0	14	13	31
12/6/00 10:08	817	6.3	5.0	18	12	34
12/6/00 12:06	822	10	8.1	15	9.0	29
12/6/00 12:41	828	10	7.9	14	8.5	32
12/6/00 14:22	825	17	14	6.2	3.6	30
12/6/00 14:56	836	17	13	8.6	3.8	28
12/7/00 11:05	791	14	12	2.5	2.4	28
12/7/00 11:40	784	14	12	2.3	2.3	24
12/7/00 13:42	785	17	14	3.0	2.1	25
12/7/00 14:16	785	17	14	-	2.1	24
12/7/00 16:45	787	0	0.0	-	8.8	27
12/7/00 17:07	787	0	0.0	-	6.7	32
12/7/00 17:45	782	0	0.0	-	15	30
12/8/00 9:36	816	0	0.0	-	17	32
12/8/00 10:11	816	0	0.0	-	21	39

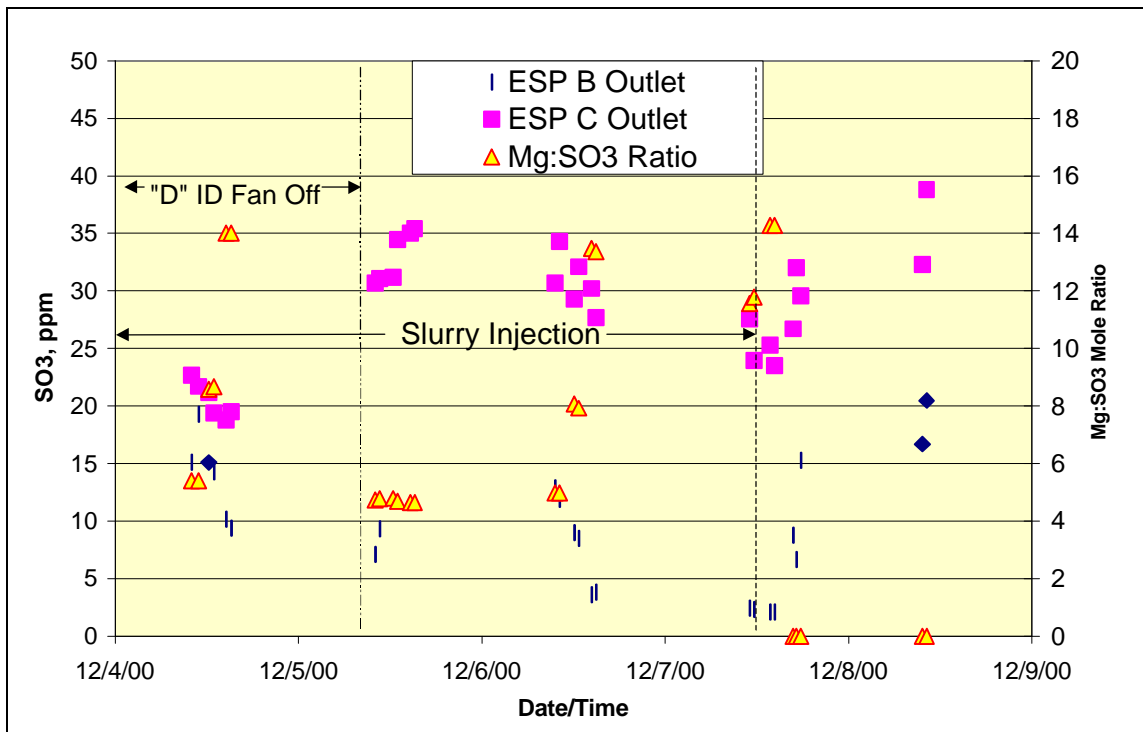
\*Lost slurry flow for approximately one hour.

\*\*Low-pressure test, 40 psig air pressure to lances.

\*\*\*Low-pressure test, 20 psig air pressure to lances.



**Figure 4-9. Results from the First Week of the Commercial Mg Test**



**Figure 4-10. Results from the Second Week of the Commercial Mg Test**

collected during the commercial Mg test, which were used in these calculations, are shown in Table 4-8.

**Table 4-8. Ultimate Analyses of Coal Samples from the Commercial Mg Test**

Parameter	Composition, wt% (except as noted)				
	11/28	11/29	12/1	12/6	12/8
Carbon	64.76	66.41	66.42	65.85	62.94
Hydrogen	4.30	4.57	4.48	4.48	4.27
Nitrogen	1.14	1.15	1.13	1.11	1.04
Sulfur	4.74	4.05	4.19	4.08	3.86
Chlorine (ppm)	NA	NA	NA	NA	NA
Oxygen	4.66	4.94	4.10	4.67	5.00
Moisture	6.36	5.48	5.30	5.25	7.57
Ash	14.04	13.40	14.38	14.56	15.32
Total	100.00	100.00	100.00	100.00	100.00
HHV (Btu/lb)	11,548	12,062	11,903	11,955	11,446

\*NA – Not analyzed

Baseline SO<sub>3</sub> sampling was conducted on November 28, and commercial Mg injection began that afternoon. The coal sample for that day showed an abnormally high sulfur content of 4.7%, but the flue gas SO<sub>3</sub> measurements prior to sorbent injection did not correspondingly indicate higher than normal SO<sub>3</sub> concentrations. The baseline measurements showed a side to side SO<sub>3</sub> stratification at the ESP outlet that was not seen in the original baseline measurements in early October. The November 28 data showed only 19 ppm of SO<sub>3</sub> at the ESP B outlet and 30 ppm at the ESP C outlet. Immediately after injection began, at a Mg:SO<sub>3</sub> ratio of about 5:1, two sets of SO<sub>3</sub> measurements showed only about 10% SO<sub>3</sub> removal at the ESP B outlet. The next day, after almost 24 hours of sorbent injection at nominally the same rate, the indicated SO<sub>3</sub> removal percentage at the ESP B outlet had increased to between 40 and 45%.

The next set of measurements were part of an overnight test, conducted November 30, with the unit load reduced to about 550 gross MW and the injection rate first increased to 10 gpm and then to 17 gpm. At the 10-gpm injection rate, corresponding to a Mg:SO<sub>3</sub> molar ratio of 11:1, the ESP B outlet SO<sub>3</sub> was observed to drop below 10 ppm, representing about 50% removal. At the 17-gpm injection rate, corresponding to a Mg:SO<sub>3</sub> ratio of almost 19:1, the ESP B outlet SO<sub>3</sub> concentration was observed to drop below 5 ppm, representing 80 to 85% removal relative to the most recent baseline value.

This test on November 30 provided clear evidence of sorbent migration to the west side of the boiler. The ESP C outlet SO<sub>3</sub> concentrations were observed to lower from the previous

day's baseline value of 28 to 30 ppm to about 17 ppm at the 11:1 Mg:SO<sub>3</sub> ratio, then to about 12 ppm at the higher ratio. It was observed that the "D" ID fan was out of service for this low load test. It was decided to conduct future testing with all four fans in service, to minimize side-to-side flue gas mixing that appeared to be caused by having one fan out of service (particularly the "D" fan).

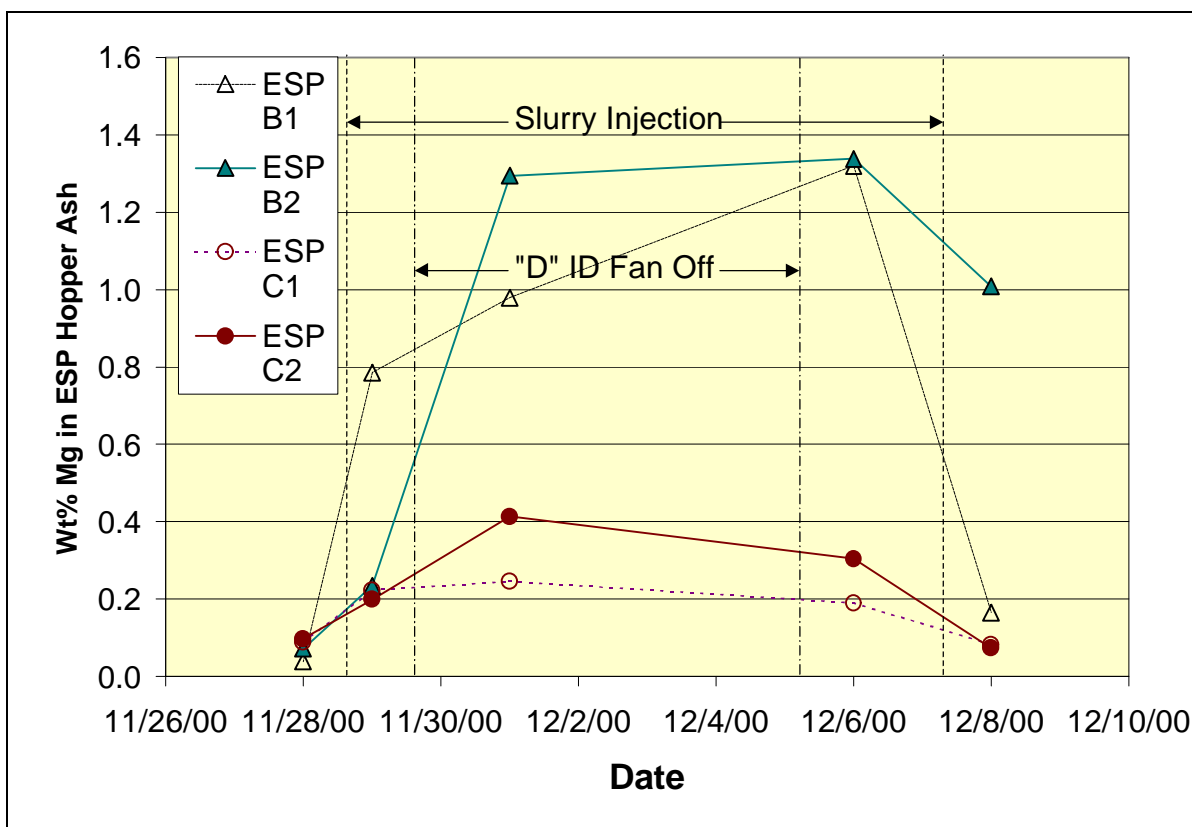
On December 1, a series of tests was conducted to screen the effects of air pressure to the slurry atomizing nozzles on SO<sub>3</sub> removal. Air pressure values of 80 psig, 40 psig, and 20 psig were tested. It was thought that higher air pressure would lead to smaller slurry droplets, and hence greater surface area in the dried solids, which should lead to improved SO<sub>3</sub> removal. However, lower air pressure would make bigger droplets, which would take longer to evaporate. This could better protect the dried solids from sintering (they would likely reach a lower maximum temperature) and the bigger droplets were also expected to better penetrate the 40-ft depth of the furnace cavity. These effects might improve SO<sub>3</sub> removal when the air pressure is reduced.

The results for December 1 show that the highest pressure produced the lowest ESP B outlet SO<sub>3</sub> concentrations. However, the overall SO<sub>3</sub> removal levels observed were relatively low. These tests were conducted with the "D" ID fan still off-line, and evidence of minor sorbent migration to the west side was seen in the ESP C outlet SO<sub>3</sub> concentrations. The C outlet concentrations were measured to be in range of 21 to 26 ppm, whereas they had ranged from 20 to 30 ppm on November 29 at the same injection rate but all four fans in service. Consequently, the nozzle air pressure screening was conducted again later in the test period. Those results, from testing on December 5, showed the same effect of air pressure, with the highest pressure being the best in terms of lowering ESP B outlet SO<sub>3</sub> concentrations. Due to limitations on the supply and pressure of plant compressed air at the 14<sup>th</sup> floor location, it was not possible to test higher air pressures than 80 psig. It is possible that better SO<sub>3</sub> removal performance could be achieved if 100 psig air were available.

Perhaps the most noteworthy results from the commercial Mg test came in the last two days of operation, December 6 and 7. By this time, the commercial Mg sorbent had been injected continuously for over a week, at injection rates corresponding to about a 5:1 Mg:SO<sub>3</sub> ratio or better. It was expected that over the period of a week or more, the boiler would be "conditioned" by reaching a steady state buildup of MgO on heat transfer surfaces, and that SO<sub>3</sub> removal performance would continually improve over time. However, after a week of continuous injection it became apparent that the SO<sub>3</sub> removal percentage desired at the ESP B outlet would not be achieved without increasing the injection rate to achieve Mg:SO<sub>3</sub> ratios well above 5:1.

From the afternoon of December 6 through the afternoon of December 7, the commercial Mg sorbent was injected at a flow rate corresponding to a Mg:SO<sub>3</sub> molar ratio of 12:1 to 14:1. After about 24 hours of injection at this rate, the observed ESP B outlet SO<sub>3</sub> concentrations were measured at about 2.3 ppm at a 12:1 mole ratio, and 2.1 ppm at a 14:1 mole ratio. These values represent approximately 90% SO<sub>3</sub> removal, the target for this project.

The data from December 7 were collected with all four Unit 3 ID fans in service. The observed migration of sorbent over to the west side of the boiler was greatly reduced with all four fans in service, with the ESP C outlet SO<sub>3</sub> concentrations measured to be near baseline at 24 to 28 ppm. Figure 4-11 illustrates magnesium concentration values measured for fly ash samples collected from the hoppers on the “B” and “C” ESP’s during the commercial Mg test. The results show that the magnesium content of the hopper ash samples from ESP C increased to about one-third those in ESP B while the “D” ID fan was out of service. This is indicative of considerable sorbent migration to the west side of the boiler. After the “D” ID fan was placed back in service, the ESP C magnesium levels decreased, although they remained somewhat higher than the baseline (no sorbent injection) levels.



**Figure 4-11. Illustration of Magnesium Concentrations in ESP Hopper Ash Samples**



In Table 4-7, the data from the evening of December 7 and the morning of December 8 show how rapidly the ESP B outlet SO<sub>3</sub> concentrations return to baseline levels after continued sorbent injection at a high rate. Within one to two hours of ceasing sorbent injection, the ESP B outlet SO<sub>3</sub> concentrations increased to a level corresponding to about 55 to 65% removal, and by the next morning, the SO<sub>3</sub> concentrations had returned to essentially baseline values. The magnesium concentration data in Figure 4-11 similarly show that the ESP hopper samples had returned to essentially baseline magnesium levels.

#### **4.2.4 Byproduct Mg Test**

The third short-term slurry injection test was conducted the weeks of February 12 and February 19, 2001, using a byproduct magnesium hydroxide produced at Allegheny Energy's Pleasants Station. The Pleasants Station has a Dravo ThioClear® FGD process that employs clear-liquor, magnesium-based scrubbing, with ex situ lime addition and forced oxidation to produce a gypsum byproduct. The remaining liquor after the gypsum is produced can be further processed by lime addition to precipitate a mixture of magnesium hydroxide and gypsum particles. This stream is purified to recover most of the gypsum, and a second byproduct is a slurry that contains a mixture of magnesium hydroxide (about 60% of the solids) and gypsum fines (most of the remaining solids). With the current equipment configuration at the Pleasants Station, this byproduct slurry is produced at about 15 to 20 wt% total suspended solids.

The solids in this slurry average about 4 to 5 microns for a mass mean particle diameter, and have a specific surface area of about 49 to 63 m<sup>2</sup>/g. The gypsum solids in this slurry most likely have a low specific surface area (less than 5 m<sup>2</sup>/g) and contribute very little to the average, so the specific surface area of the magnesium hydroxide in this slurry is probably in the range of 70 to 100 m<sup>2</sup>/g.

For the short-term byproduct Mg slurry injection test, the byproduct slurry was trucked from the Pleasants Station and unloaded into the 10,000-gallon storage tanks at BMP Unit 3. Several truckloads per day were required at the slurry injection rates tested.

The results from the byproduct Mg test are summarized in Table 4-9, and plotted in Figures 4-12 (first week) and 4-13 (second week). The Mg:SO<sub>3</sub> molar ratios in the table are based on the amount of Mg in the byproduct slurry, one-half the Unit 3 coal feed rate, and ultimate analyses of coal samples for this time period. The coal ultimate analyses are summarized in Table 4-10. The results in Table 4-10 show that the coal quality was quite

variable during the two-week test period, and that coal sulfur levels were generally lower than they had been during

**Table 4-9. Summary of Results from Short-term Byproduct Mg Test on Unit 3**

<b>Date/Time</b>	<b>Unit Load, gross MW</b>	<b>Mg:SO<sub>3</sub> Molar Ratio</b>	<b>Air Heater Outlet/ ESP B Inlet</b>	<b>ESP B Outlet</b>	<b>ESP C Outlet</b>
2/13/01 9:48	771	0.0	36	-	35
2/13/01 10:35	716	0.0	32	-	31
2/13/01 13:04	715	0.0	38	24	31
2/13/01 13:53	716	0.0	-	33	-
2/13/01 14:28	716	0.0	-	30	-
<b>Average</b>			36	29	32
2/14/01 7:42	654	0.0	41*	31*	_*
2/14/01 8:20	653	0.0	43*	35*	_*
2/14/01 8:58	658	0.0	42*	33*	_*
2/14/01 9:34	658	0.0	28*	26*	_*
2/14/01 10:09	680	0.0	17**	20**	29**
2/14/01 12:21	678	4.4	18**	14**	27**
2/14/01 12:55	677	4.7	14**	13**	29**
2/14/01 13:51	638	5.4	14**	11**	25**
2/14/01 15:20	611	5.7	-	10**	25**
2/15/01 9:50	782	6.1	18**	12**	28**
2/15/01 10:30	782	6.1	14**	10**	28**
2/15/01 11:24	755	6.4	17**	-	27**
2/15/01 13:31	755	6.4	17**	11**	30**
2/15/01 14:04	755	5.6	17**	12**	28**
2/15/01 14:37	755	5.6	14**	11**	27**
<b>Average</b>			16**	11**	28**
2/16/01 9:39	777	3.9	8.0**	11**	36**
2/16/01 10:36	769	0.4	20**	17**	28**
2/16/01 11:12	774	4.5	20**	12**	26**
2/16/01 11:39	774	6.4	37**	-	-
2/16/01 13:13	771	8.8	20**	15**	28**
2/16/01 14:20	772	8.8	26	17	32
2/16/01 15:06	772	8.8	19	17	31
2/19/01 9:20	808	0.0	31	29	38
2/19/01 9:49	807	0.0	36	29	33
2/19/01 10:23	807	0.0	38	26	34

**Table 4-10. (Continued)**

<b>Date/Time</b>	<b>Unit Load, gross MW</b>	<b>Mg:SO<sub>3</sub> Molar Ratio</b>	<b>Air Heater Outlet/ ESP B Inlet</b>	<b>ESP B Outlet</b>	<b>ESP C Outlet</b>
2/19/01 14:42	804	3.2	20	17	34
2/19/01 15:17	807	3.3	21	15	30
2/19/01 15:52	806	3.3	21	13	31
2/20/01 9:29	787	3.9	13	12	35
2/20/01 10:05	810	3.8	21	11	35
2/20/01 10:39	810	3.8	23	11	35
2/20/01 11:14	815	3.8	-	11	35
2/20/01 11:50	811	3.8	17	10	34
2/21/01 9:49	800	5.4	8.3	7.3	30
2/21/01 10:24	802	7.2	5.1	3.9	24
2/21/01 11:19	794	7.3	4.5	2.0	24
2/21/01 12:10	770	7.0	3.7	1.7	20
2/21/01 13:03	807	7.1	3.8	2.4	25
2/22/01 9:23	814	6.9	36	8.9	38
2/22/01 10:00	811	4.1	32	14	39
2/22/01 11:47	769	4.4	27	23	40
2/22/01 12:21	807	4.1	45	28	40
2/22/01 12:58	748	4.5	32	18	39

\*"C" ID fan out of service

\*\*"A" ID fan out of service

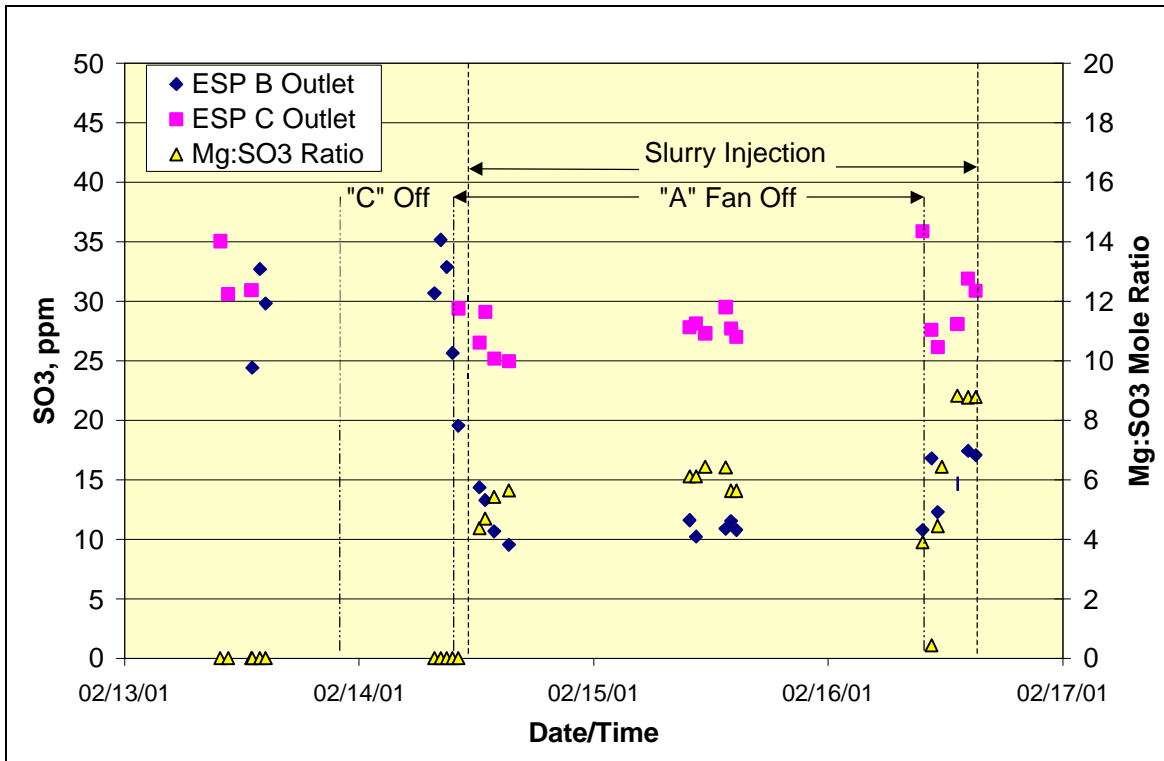


Figure 4-12. Results from the First Week of the Byproduct Mg Test (11<sup>th</sup> floor injection)

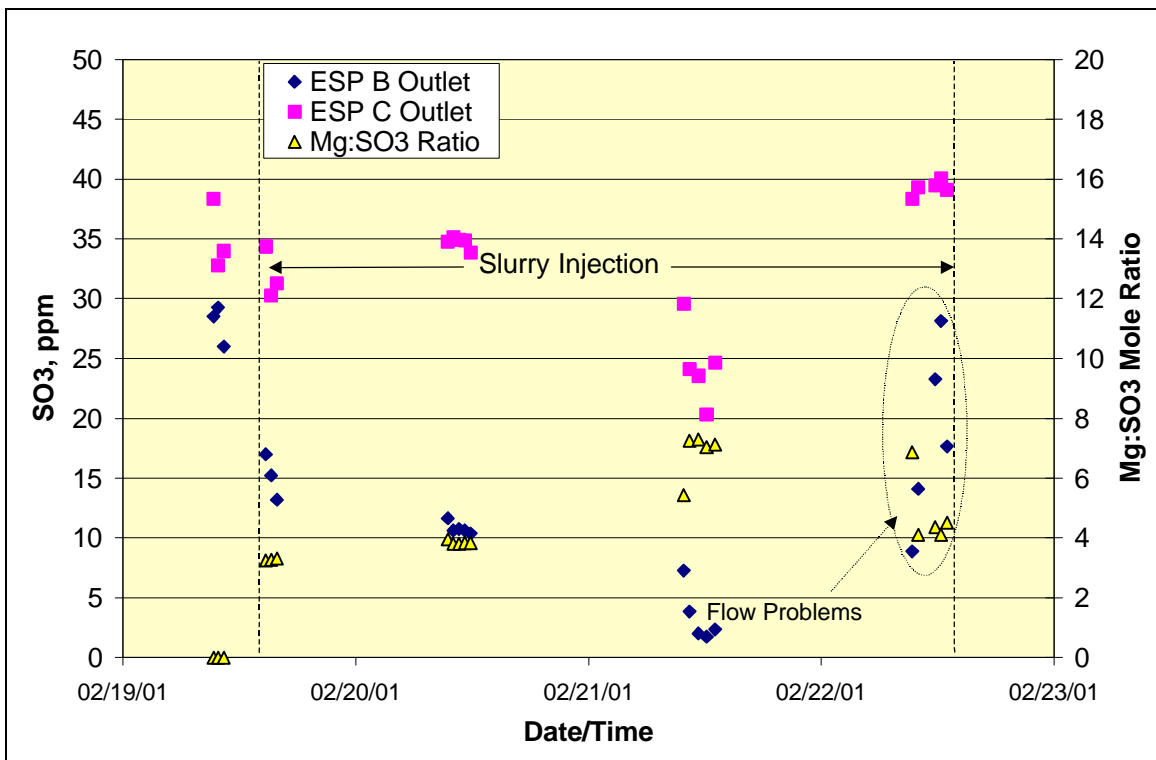


Figure 4-13. Results from the Second Week of the Byproduct Mg Test (14<sup>th</sup> floor injection)

**Table 4-11. Ultimate Analyses of Coal Samples from the Byproduct Mg Test**

<b>Parameter</b>	<b>Composition, wt% (except as noted)</b>				
	<b>2/14</b>	<b>2/15</b>	<b>2/19</b>	<b>2/20</b>	<b>2/23</b>
Carbon	66.05	67.51	65.31	61.76	69.09
Hydrogen	4.28	4.44	4.23	3.74	4.13
Nitrogen	1.22	1.24	1.17	1.16	1.30
Sulfur	3.39	3.56	3.69	3.35	3.48
Chlorine (ppm)	NA	NA	NA	NA	NA
Oxygen	4.69	4.55	4.92	3.90	3.81
Moisture	7.49	5.92	7.05	8.50	7.00
Ash	12.88	12.78	13.63	17.59	11.19
Total	100.00	100.00	100.00	100.00	100.00
HHV (Btu/lb)	11,995	11,938	11,504	10,991	12,317
lb SO <sub>2</sub> /MM Btu	5.65	5.96	6.42	6.10	5.65

\*NA – Not analyzed

the previous weeklong baseline period and the two previous short-term slurry injection tests. The coal sulfur averaged about 3.5 wt% for this test versus about 4% for the previous tests.

Unfortunately, this test was conducted during a time period that the supply of high-sulfur bituminous coal was tight in that part of the country, so the typical coal blend fired at BMP was not available.

In spite of the coal sulfur analyses showing lower sulfur content, the baseline SO<sub>3</sub> concentrations measured on February 13 are as high as previous measurements with the higher-sulfur coals. Given that normal flue gas SO<sub>3</sub> concentrations were seen, the Mg:SO<sub>3</sub> ratios shown in the table and figures may be biased high by 10 to 15% because of the lower coal sulfur values used for the calculations.

Note in the table that most of the baseline samples for this short-term test were taken with an ID fan out of service (“A” or “C”). Since the ID fans in service affect the flow rates through the air heaters, they can also affect the downstream SO<sub>3</sub> concentrations. This may explain why the baseline values for the ESP B outlet location were initially measured to be higher than they had been for the previous commercial Mg test. After the “C” fan was put back in service and the “A” fan was taken out of service around 10:00 a.m. on February 14, the ESP B outlet concentration was measured to drop to about 20 ppm (one measurement), which is consistent with what it had measured during the commercial Mg test.

Unit 3 continued to operate on three ID fans (“A” fan out of service) through Friday afternoon of the first week of the test. Most of the testing was conducted with Mg:SO<sub>3</sub> molar ratios of about 5:1 to 6:1, and ESP B outlet SO<sub>3</sub> concentrations were typically measured at about 10 to 12 ppm. This represents about 40 to 50% SO<sub>3</sub> removal based on 20 ppm as a baseline value, or 60 to 70% removal if the baseline values were actually around 30 ppm as they had been earlier in the week.

Late in the afternoon on Friday, February 16, the slurry injection rate was raised to the maximum achievable value, which corresponded to a Mg:SO<sub>3</sub> molar ratio of almost 9:1. Midway through the afternoon, the boiler operators placed the “A” ID fan back in service, meaning all four ID fans were operating. The ESP B outlet SO<sub>3</sub> concentrations measured at this high injection rate were disappointingly high, ranging from 15 to 17 ppm.

Because it had not proven to be possible to control the ESP B outlet SO<sub>3</sub> concentrations down below 5 ppm as desired, it was decided to move the injection location up higher in the furnace, injecting through the inspection ports at the 14<sup>th</sup> floor of the boiler structure. The injection system was shut down over the weekend while the nozzles were repositioned, and testing resumed on Monday, February 19.

During the second week of testing, Unit 3 operated with all four ID fans in service the entire week. The baseline SO<sub>3</sub> concentrations measured for the ESP B outlet were relatively high, averaging 28 ppm. Injection began in the early afternoon, at an effective Mg:SO<sub>3</sub> molar ratio of about 3:1, and by later in the afternoon the measured ESP B outlet SO<sub>3</sub> concentration was down to 13 ppm, representing over 50% removal. Injection continued through the next day at a rate corresponding to a Mg:SO<sub>3</sub> ratio of nearly 4:1, and ESP B outlet SO<sub>3</sub> concentrations dropped to about 10 to 11 ppm, representing just over 60% SO<sub>3</sub> removal compared to the previous day’s baseline.

However, the desire was still to lower the ESP B outlet SO<sub>3</sub> concentration to below 5 ppm, so overnight the injection rate was increase to a Mg:SO<sub>3</sub> molar ratio of about 5:1 to 6:1. The first measurement the morning of February 21 showed the ESP B outlet had dropped to about 7 ppm, representing over 70% removal. A further increase in injection rate during the day, to a Mg:SO<sub>3</sub> ratio of about 7:1, lowered the ESP B outlet SO<sub>3</sub> concentrations to an average of 2 ppm. This represents over 90% SO<sub>3</sub> removal compared to the baseline values from Monday, February 19.

The ESP C outlet showed evidence of sorbent crossover to the west side of the furnace when injecting at this higher rate. The ESP C outlet values dropped from about 35 ppm the day

before to about 20 to 25 ppm when injecting at a 7:1 Mg:SO<sub>3</sub> ratio. ESP hopper ash samples were not taken on this day, so it is not possible to substantiate this apparent sorbent crossover based on magnesium levels in the ESP C hoppers.

It was desired to continue injecting at an intermediate rate overnight, midway between a 4:1 and 7:1 Mg:SO<sub>3</sub> molar ratio. The sorbent injection test was scheduled to end the next afternoon, February 22, after SO<sub>3</sub> concentrations were measured for the intermediate rate. Since the completion of the test was nearing, the 10,000 gallon storage tanks were depleted of inventory during the day on February 22. Although the injection system ran smoothly overnight, as the tank inventories began to deplete the morning of February 22, the injection rate became unstable due to continued pump suction line plugging. The result of the intermittent injection during the day of February 22 is that the ESP B outlet SO<sub>3</sub> concentrations measured were much higher than were expected based on the results of the previous day. Also, the ESP C outlet data from February 22 suggest a higher than normal baseline SO<sub>3</sub> for that day, with the ESP C outlet values averaging almost 40 ppm.

Thus, the objective of the project of achieving greater than 90% SO<sub>3</sub> removal, as measured at the ESP B outlet location, was achieved with the byproduct Mg slurry after the injection location was raised to the 14<sup>th</sup> floor elevation. Due to the slurry injection flow problems on February 22, it was not possible to get more information about removal versus injection rate for a “conditioned” boiler.

#### **4.2.5 Balance of Plant Effects**

Balance of plant effects measured were primarily focused on the impacts of sorbent injection and SO<sub>3</sub> removal on ESP performance during the short-term slurry injection tests. However, baseline measurements were also made of halogen species concentrations in the Unit 3 flue gas, and particulate loadings in the ESP outlet flue gas. It was decided not to evaluate these additional parameters for each short-term test. Instead, effects of sorbent injection on flue gas halogen species concentrations and on ESP outlet particulate loadings will be made during the upcoming long-term test.

##### **4.2.5.1 Impacts of Sorbent Injection and SO<sub>3</sub> Removal on ESP Operation**

During the short-term sorbent injection tests on Unit 3, the impacts of sorbent injection and SO<sub>3</sub> removal on ESP operation were measured in as many as three different manners. First, the ESP electrical properties were measured, by recording ESP electrical operating conditions

(secondary current and voltage) and V-I curves, for each electrical section several times each test. Second, the outputs from the unit's ESP outlet opacity monitors were retrieved from the plant's data archive for these time periods and reviewed. Finally, for one test, the impact of sorbent injection and SO<sub>3</sub> removal was quantified by measuring the fly ash resistivity at the air heater outlet, using an in situ Wahlco resistivity probe.

Note that the impacts from sorbent injection may be different than the impacts from any resulting SO<sub>3</sub> removal. Sorbent injection could have adverse effects if the sorbent has a higher bulk particle resistivity than the fly ash particles. If the resistivity increases into an undesirable range, the corona current in the ESP fields could be limited to low levels by the onset of sparking, and the ability to charge and collect the particles could be severely limited. Also, the addition of the fine particles represented by the injected sorbent can lead to space charge effects that would lower the resulting corona current at a given applied voltage. On the other hand, removal of SO<sub>3</sub> upstream of the ESP could have an adverse effect on the resistivity of the fly ash particles themselves. If the SO<sub>3</sub> is removed by the sorbent before it has a chance to be adsorbed onto fly ash particles, it could result in greatly increased fly ash resistivity. Thus, the net result of either the sorbent injection or SO<sub>3</sub> removal on ESP operation might be similar, just the mechanism would differ.

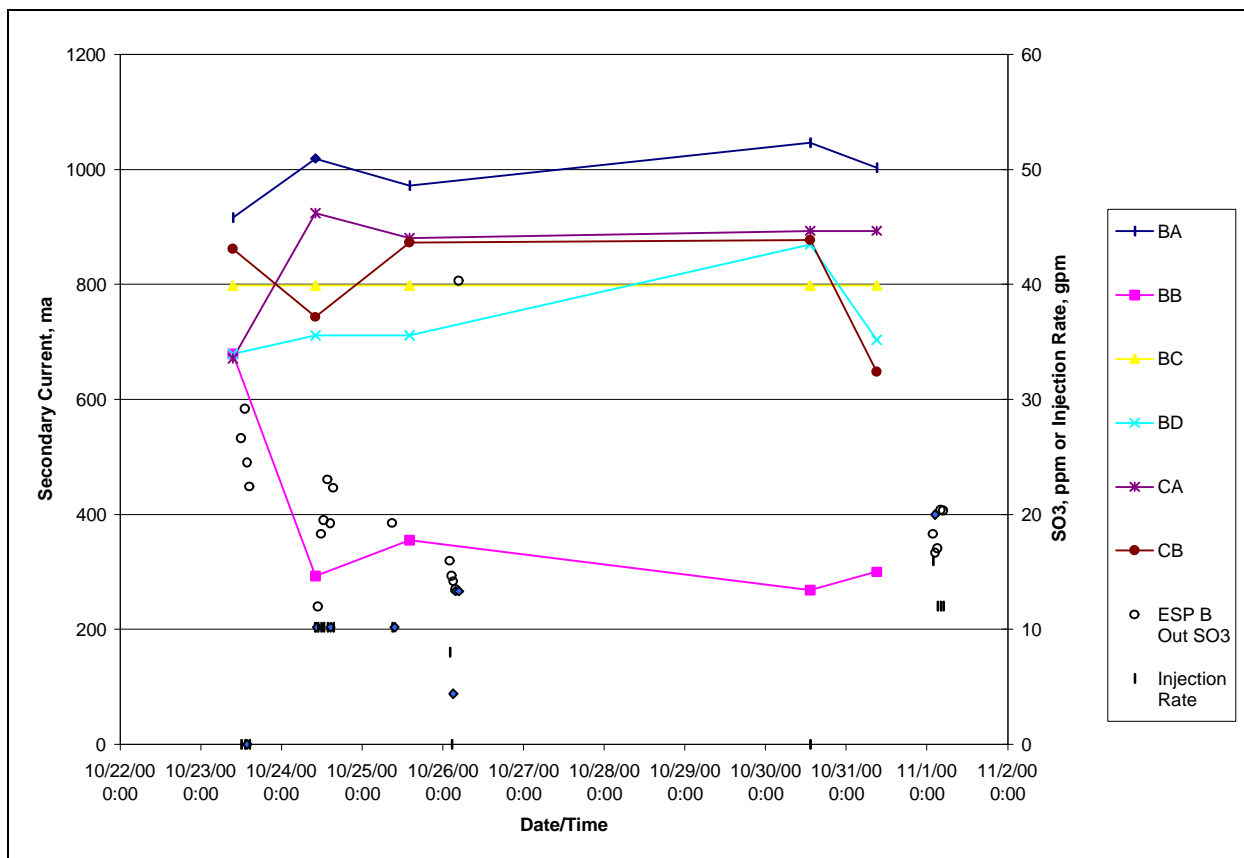
The following describes the data collected during the three short-term slurry injection tests, and what those data indicate about ESP impacts.

### ***PHDL Injection Test***

The PHDL injection test saw moderately high slurry injection rates (up to 20 gpm at 35 wt% solids) but never saw high SO<sub>3</sub> removal percentages. The lowest SO<sub>3</sub> concentration measured at the ESP B outlet was still greater than 10 ppm, which should be adequate for fly ash conditioning at the 300°F flue gas temperature in ESP B. The ESP B inlet concentrations were even higher, so no effect of SO<sub>3</sub> removal on fly ash resistivity would be expected.

Figure 4-14 illustrates the effects of sorbent injection and SO<sub>3</sub> removal on the ESP secondary current values. The secondary current values for all four electrical fields of ESP B are shown, as are data for the first two fields of ESP C. Also shown in the figure are PHDL slurry injection rates and ESP B outlet SO<sub>3</sub> concentrations. The data show no effect of sorbent injection on secondary currents. Although the secondary current in the second field of ESP B (BB) dropped with the beginning of sorbent injection, this drop appears to be coincidental and not related to PHDL injection, for two reasons. First, there was no observed effect of the PHDL on the upstream field (BA), and it seems logical that the first field would also be effected. Second,





**Figure 4-14. Observed Effect of PHDL Injection on ESP B and C Secondary Currents**

the drop in secondary current persisted after several days with no sorbent injection (see the data point on October 30).

From the data plotted in Figure 4-14, it can be concluded that the PHDL itself did not measurably affect the ESP electrical conditions, nor did the moderate amount of  $\text{SO}_3$  removal achieved when injecting this sorbent.

Also during the PHDL test, fly ash resistivity measurements were made by subcontractor CT&E Emissions Testing Services. Those measurements confirmed that the addition of the PHDL sorbent did not increase the fly ash resistivity. The measurements are summarized in Table 4-11.

The baseline data in the table started at very high values, but the measured values continued to drop through the first seven individual measurements. The final stable value of  $4.4 \times 10^{11}$  ohm-cm through the last eight measurements is taken to be the baseline value. This is borderline high resistivity, which is surprising for a high-sulfur coal with ample  $\text{SO}_3$  in the flue

**Table 4-12. Fly Ash Resistivity Measurements on Unit 3 during Baseline and PHDL Injection**

<b>Date</b>	<b>Port/Run Number</b>	<b>Time</b>	<b>Flue Gas Temperature, °F</b>	<b>Resistivity, ohm-cm</b>
10/11/00 (Baseline)	A-Run 1	13:10	294	$2.0 \times 10^{14}$
		13:25	298	$2.0 \times 10^{14}$
		13:40	298	$5.0 \times 10^{13}$
		13:55	297	$4.4 \times 10^{13}$
		14:10	298	$4.4 \times 10^{13}$
		<b>Average</b>		<b><math>1.1 \times 10^{14}</math></b>
	A-Run 2	14:25	298	$1.4 \times 10^{12}$
		14:35	299	$4.4 \times 10^{11}$
		14:50	299	$4.4 \times 10^{11}$
		15:05	298	$4.4 \times 10^{11}$
		15:25	299	$4.5 \times 10^{11}$
		<b>Average</b>		<b><math>6.3 \times 10^{11}</math></b>
	A-Run 3	15:40	299	$4.4 \times 10^{11}$
		15:55	298	$4.4 \times 10^{11}$
		16:10	299	$4.4 \times 10^{11}$
		16:25	299	$4.4 \times 10^{11}$
		<b>Average</b>		<b><math>4.4 \times 10^{11}</math></b>
10/23/00 (PHDL Injection)	A-Run 1	12:15	324	$4.7 \times 10^9$
		12:30	324	$4.5 \times 10^9$
		12:45	323	$4.5 \times 10^9$
		13:00	323	$4.5 \times 10^9$
		<b>Average</b>		<b><math>4.6 \times 10^9</math></b>
	A-Run 2	13:15	325	$4.2 \times 10^9$
		13:30	325	$4.2 \times 10^9$
		13:45	325	$4.3 \times 10^9$
		14:00	325	$4.3 \times 10^9$
		<b>Average</b>		<b><math>4.3 \times 10^9</math></b>
	A-Run 3	14:15	324	$4.3 \times 10^9$
		14:30	325	$4.3 \times 10^9$
		14:45	325	$4.3 \times 10^9$
		15:00	325	$4.2 \times 10^9$
		<b>Average</b>		<b><math>4.3 \times 10^9</math></b>
10/24/00 (PHDL Injection)	B-Run 4	08:15	320	$4.5 \times 10^9$
		08:30	320	$4.5 \times 10^9$
		08:45	320	$4.4 \times 10^9$
		09:00	318	$4.4 \times 10^9$
		<b>Average</b>		<b><math>4.4 \times 10^9</math></b>
	B-Run 5	09:15	318	$4.4 \times 10^9$
		09:30	318	$4.3 \times 10^9$
		09:45	318	$4.3 \times 10^9$
		10:00	318	$4.4 \times 10^9$
		<b>Average</b>		<b><math>4.4 \times 10^9</math></b>

gas. However, these measurements were taken with a Wahlco probe rather than the preferred SRI point-to-plane probe. The Wahlco probe is known to produce a high bias of up to one order of magnitude under some conditions relative to measurements with the SRI probe.

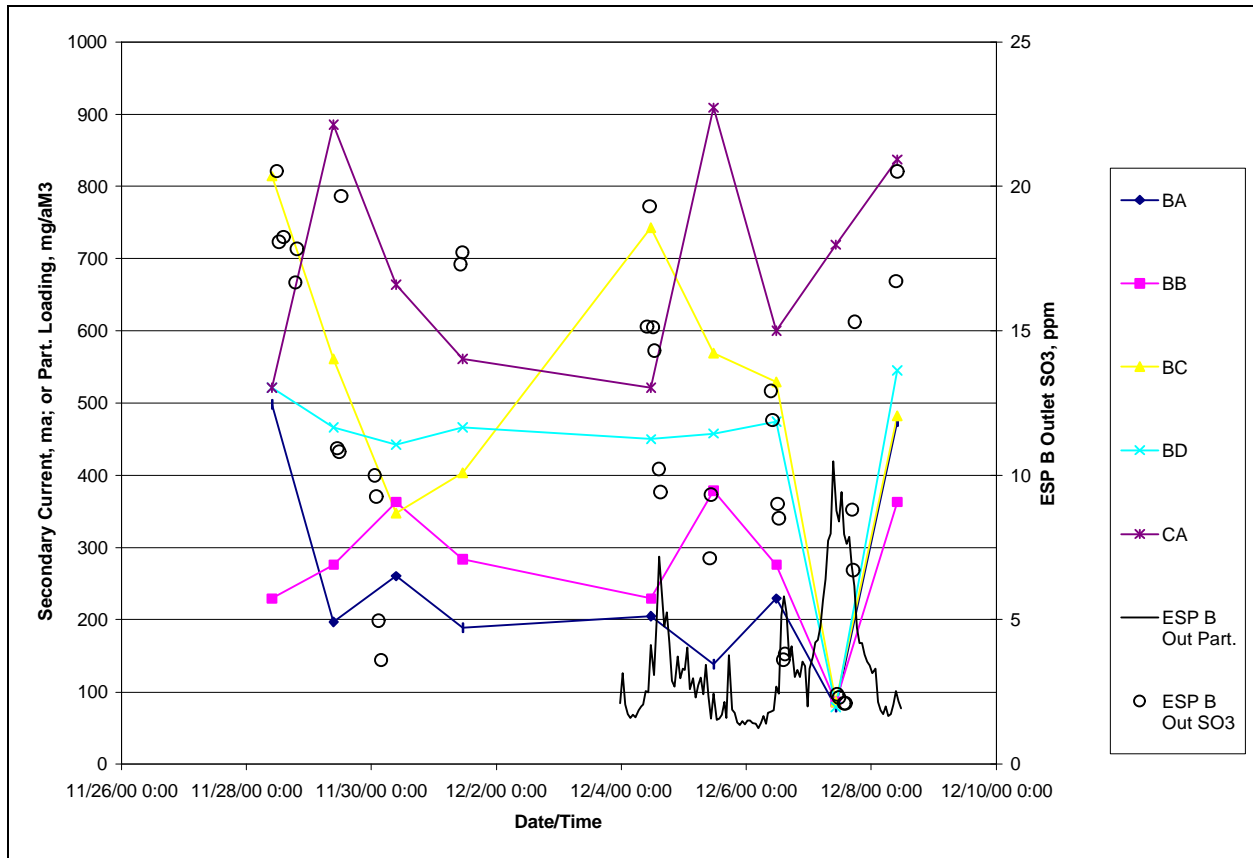
The PHDL injection data show surprisingly low resistivities during PHDL injection. The measured values of  $4\text{--}5 \times 10^9$  ohm-cm are below the ideal range for ESP operation. It is not clear why the injection of the PHDL slurry would lower resistivity values by two orders of magnitude relative to baseline. At any rate, these values at least confirm that the sorbent addition did not cause high resistivity, as was previously indicated by the absence of an effect on the ESP operating data.

### ***Commercial Mg Injection Test***

The commercial Mg was the first slurry injection test that was successful at achieving approximately 90% SO<sub>3</sub> removal as measured at the ESP B outlet, lowering the ESP B outlet SO<sub>3</sub> concentrations to 2 ppm. ESP B inlet SO<sub>3</sub> concentrations were measured to have been lowered into the range of 2 to 3 ppm. Figure 4-15 illustrates secondary current values for all four electrical sections of ESP B, and for the first section of ESP C during the test period. Also shown are the ESP B outlet SO<sub>3</sub> concentrations measured, and the ESP B outlet particulate loading as indicated by the plant's opacity monitor (second week of the test only). The data in Figure 4-15 show an immediate drop in the secondary current at the first field of ESP B as soon as sorbent injection begins, with the values dropping from about 500 mA to approximately 200 to 250 mA. Effects on the downstream fields are not as consistent, with some fields increasing and some decreasing after sorbent injection begins. We would expect initial effects of sorbent injection to be most pronounced for the first field of the B ESP, most likely due to a space charge effect from the additional small particles added to the flue gas by the sorbent.

The most pronounced effect in the figure is seen for December 7, when the sorbent injection rate was high, and the ESP B outlet SO<sub>3</sub> was lowered to approximately 2 ppm. ESP operating conditions were measured during the same time period, and show a profound effect on the ESP B electrical conditions. The secondary current values for all four electrical sections were lowered to below 100 mA. Similarly, the power input to those electrical sections (not shown in the figure) was lowered to about 3 kW during this period, as opposed to normal input values in the range of 20 to 40 kW.

The ESP B outlet opacity shows a dramatic increase in mass loading at the ESP B outlet during this same time period. It is not known how well this instrument output is calibrated to



**Figure 4-15. Observed Effect of Commercial Mg Injection on ESP B and C Secondary Currents and ESP B Particulate Emissions**

actual mass loading, but note that the indicated highest value of about 400 mg per actual cubic meter corresponds with a loading of about 0.27 gr/dscf, or an emission rate of over 0.5 lb/10<sup>6</sup>Btu. Fortunately, only one of four ESP's was affected to such an extent.

Also note that the observed ESP electrical conditions and outlet emissions levels appear to be directly related to sorbent injection and/or SO<sub>3</sub> removal, as values from the next day, after sorbent injection was stopped, were returned to normal. It appears that the commercial Mg injection rate and/or SO<sub>3</sub> removal down to 2 ppm in the ESP B outlet gas had a catastrophic effect on ESP performance. This was not noted during the test, most likely because only one ESP of four was affected to such an extent, and the duration of the apparently increased emission rates was only for a few hours. Continued operation on the entire furnace at this injection rate and/or SO<sub>3</sub> removal level would not likely be possible, as the particulate emissions rates from the ESP would probably exceed acceptable levels.

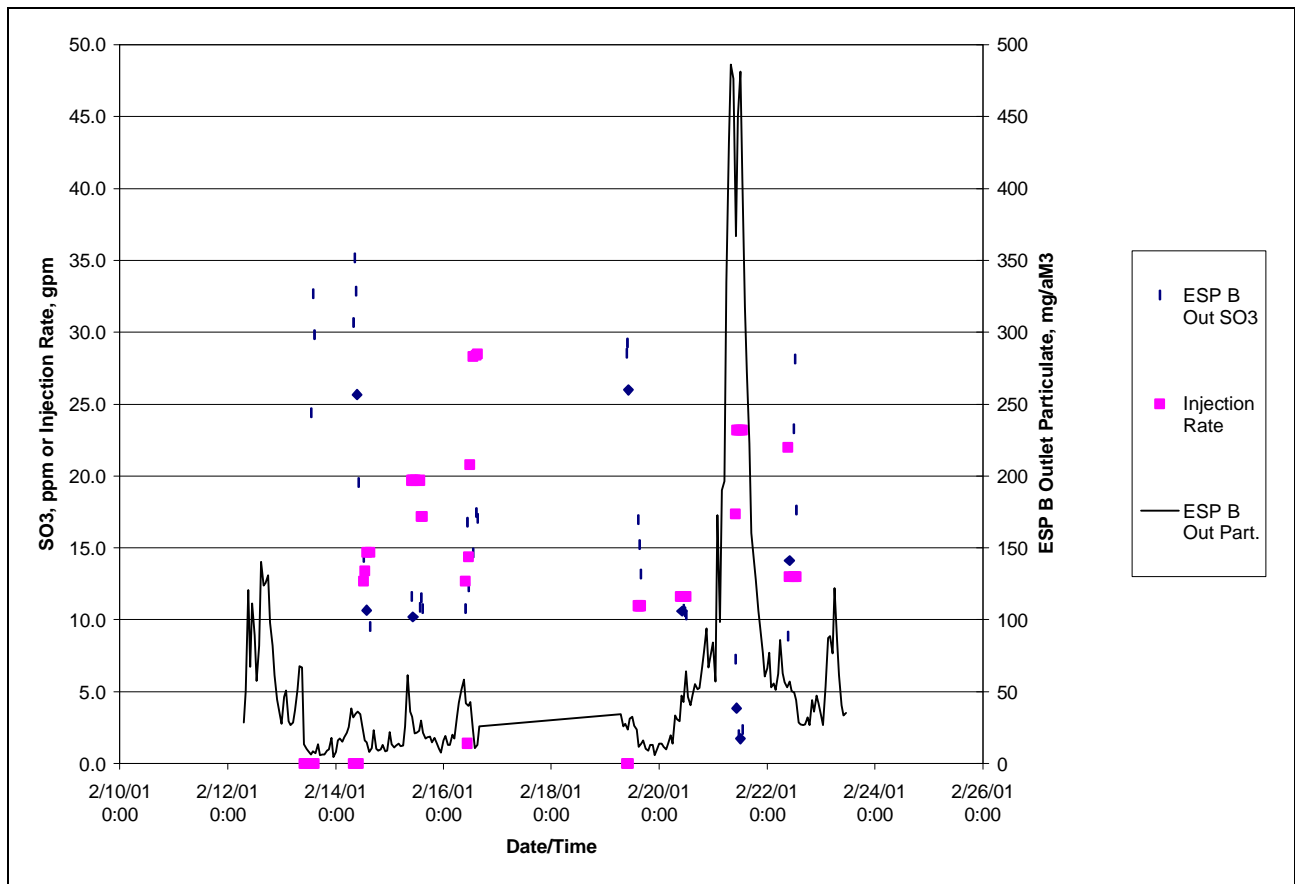
### ***Byproduct Mg Injection Test***

The byproduct Mg test was the second slurry injection test successful at achieving approximately 90% SO<sub>3</sub> removal as measured at the ESP B outlet. The ESP B inlet SO<sub>3</sub> concentrations were measured to have been lowered into the range of 3 to 4 ppm, and the outlet concentrations to 2 ppm. ESP impacts during the byproduct Mg injection test are summarized in Figure 4-16. Due to technical difficulties, ESP operating current and voltage values were not recorded for this test. Therefore Figure 4-16 does not include any secondary current values for ESP B, only the byproduct Mg slurry injection rate, the ESP B outlet SO<sub>3</sub> concentrations measured, and the ESP B outlet particulate loading as indicated by the plant's opacity monitor. The latter are the only available information about the effects of byproduct Mg injection on ESP operation.

The most pronounced effect in the figure is seen overnight on February 20 and during the day on February 21, when the sorbent injection rate was high, and the ESP B outlet SO<sub>3</sub> concentration was lowered to approximately 2 ppm. The ESP B outlet opacity shows a dramatic increase in mass loading during this same time period. Note that the observed adverse effect appears to be directly related to the effects of high SO<sub>3</sub> removal, as values from the next day returned to normal, after sorbent injection rates were reduced and the ESP B outlet SO<sub>3</sub> concentrations increased to 9 ppm and greater. The adverse effect does not appear to be related to sorbent injection rate per se, as a higher injection rate was experienced the previous week, on February 16, with no apparent effect on ESP particulate emissions. The February 16 data were for slurry injection at the 11<sup>th</sup> rather than 14<sup>th</sup> floor, and high SO<sub>3</sub> removal efficiencies were not seen. This observation suggests that it is the low flue gas SO<sub>3</sub> concentrations rather than the presence of the additional calcium and magnesium compounds that adversely affect ESP performance.

Figure 4-17 repeats the data in Figure 4-16 from the second week of the test, but adds outlet emissions levels from the "A" and "D" ESP's. The ESP C data are not included because the monitor output showed essentially zero outlet emissions during the entire period, perhaps due to instrument malfunction.

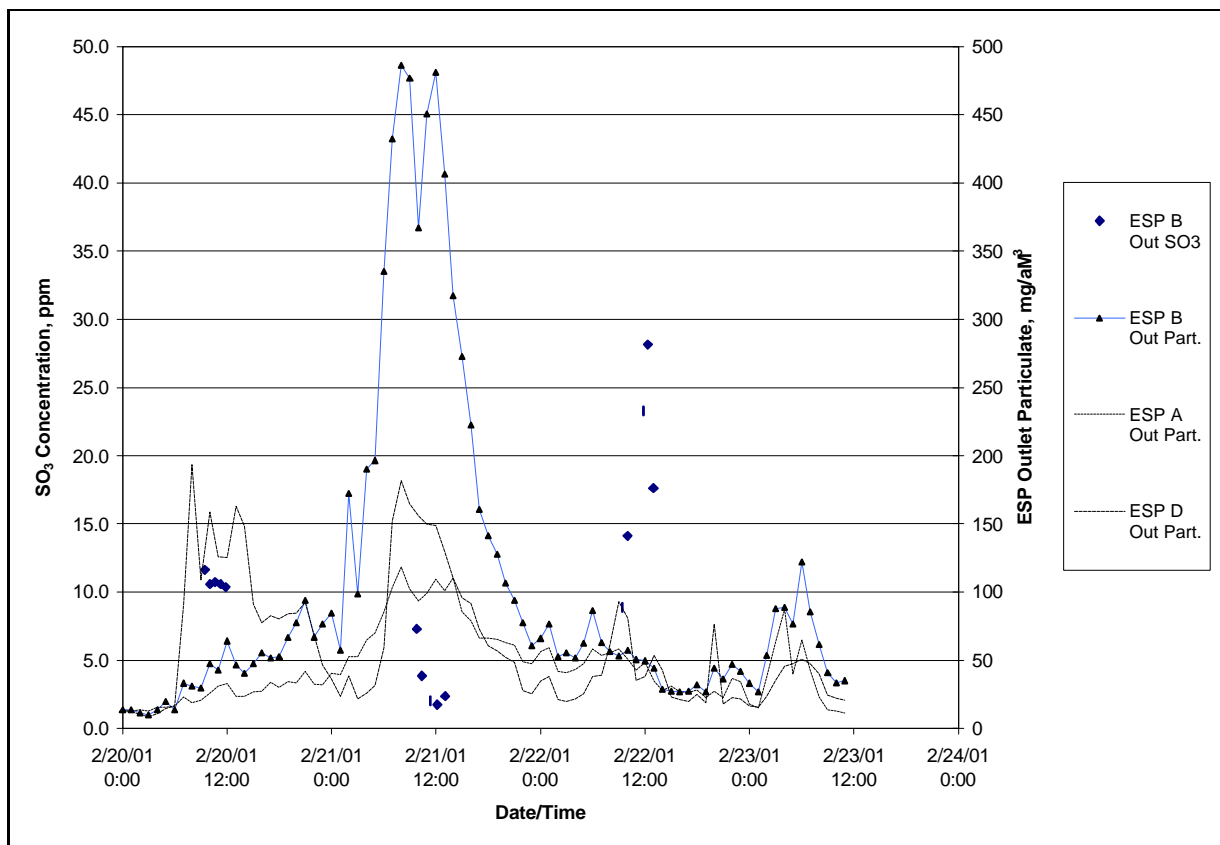
The data in Figure 4-17 suggest that the other ESP's were also affected by the byproduct Mg injection to achieve low SO<sub>3</sub> concentrations on the east side of the boiler, but to a much lesser extent than ESP B. ESP A is on the side experiencing injection, but showed only a minor effect on outlet particulate levels during this period. This may be because ESP A receives gas from the "cold" side of the air heater, so the flue gas treated is much cooler than that treated



**Figure 4-16. Observed Effect of Byproduct Mg Injection on ESP B Particulate Emissions**

on the ESP B. These data suggest that at the lower flue gas temperature, much lower  $\text{SO}_3$  concentrations are adequate for fly ash conditioning than are required for ESP B. Such a relationship is consistent with theory.

The ESP D data are from the side of the boiler not receiving slurry injection, but appear to show an adverse effect on outlet emissions. There are two possible explanations for the observed effect. One is that these data support earlier indications that when injecting at high rates on the east side, some sorbent flow and  $\text{SO}_3$  removal are seen on the west side gas path. It would be surprising, though, that the effect on the “D” ESP would be more pronounced than on the “A” ESP, which is on the side receiving slurry injection. A more likely explanation is that this peak in observed particulate emissions from the “D” ESP is coincidental. A peak of similar magnitude was seen in the ESP D outlet on February 20, during a period when both the “A” and “B” ESP’s were seeing normal outlet emissions levels. Whatever caused that peak may have similarly affected the ESP D emissions on February 21.



**Figure 4-17. ESP Outlet Emissions Data from the Byproduct Mg Injection Test**

It appears that the  $\text{SO}_3$  removal resulting from byproduct MG injection, down to 2 ppm in the ESP B outlet gas, had a catastrophic effect on ESP B performance. Again, this was not noted during the test, probably because only one ESP of four was affected to such an extent, and the duration of increased emission rates was only for a few hours. It is clear that for continued operation on the entire furnace, the injection rate and  $\text{SO}_3$  removal level will be limited by ESP performance. For the long-term test, we will have to operate at a slurry injection rate that is optimized to achieve the maximum possible level of  $\text{SO}_3$  removal while maintaining acceptable ESP particulate control performance. It is not possible to project that control level from the limited amount of data available. However, from the data available it appears that the “B” and “C” ESP out  $\text{SO}_3$  concentrations will have to be maintained somewhere in the range of 5 to 8 ppm unless some other form of fly ash resistivity conditioning (e.g., flue gas humidification) is employed.

#### 4.2.5.2 ESP Outlet Particulate Loading

Baseline measurements were made of the ESP B outlet particulate loadings. These values will be compared to outlet particulate loading measurements during the long-term sorbent injection test, to better evaluate sorbent effects on ESP performance. Measurements were made in two manners. One type was using the sampling train for EPA Method 17, and the second was to collect and weigh fly ash solids captured in the Method 26a sample train (halogens in flue gas). Also, the gas was sampled in three different manners: a full traverse of the ESP B outlet duct, a traverse across a single port, and single-point sampling at a given point in a particular port. The results of ESP B outlet particulate loading measurements by these various techniques are summarized in Table 4-12.

**Table 4-13. Summary of ESP B Outlet Baseline Particulate Loading Measurements**

<b>Date</b>	<b>Method</b>	<b>Traverse/Single Point</b>	<b>Weight of Particulate Collected, grams</b>	<b>Quantity of Flue Gas Sampled, dscf</b>	<b>Particulate Concentration, grains/dscf</b>	<b>Particulate Emission Rate, lb/MMBtu</b>
10/03/00	26a	ESP B Full Traverse	0.1533	66.089	0.036	0.072
10/04/00	17	ESP B Full Traverse	0.0867	46.277	0.029	0.058
10/05/00	26a	ESP B Full Traverse	0.2204	71.137	0.048	0.096
10/06/00	17	ESP B Full Traverse	0.0934	47.15	0.031	0.061
<b>Average</b>					<b>0.036</b>	<b>0.072</b>
10/04/00	26a	Port 4 Traverse	0.3579	66.823	0.083	0.165
10/04/00	17	Port 4 Traverse	0.0567	38.262	0.023	0.046
<b>Average</b>					<b>0.053</b>	<b>0.106</b>
10/03/00	26a	Port 3?, Point 3?	0.089	68.162	0.020	0.040
10/04/00	17	Port 3, Point 3	0.0953	46.183	0.032	0.064
<b>Average</b>					<b>0.026</b>	<b>0.052</b>
10/05/00	26a	Port 4, Point 3	0.2887	68.86	0.065	0.129
10/06/00	17	Port 4, Point 3	0.0506	40.159	0.019	0.039
<b>Average</b>					<b>0.042</b>	<b>0.084</b>
10/05/00	26a	Port 4, Point 2	0.269	70.587	0.059	0.118
10/06/00	17	Port 4, Point 2	0.1277	39.021	0.051	0.101
<b>Average</b>					<b>0.055</b>	<b>0.109</b>

The results in the table show that the ESP outlet loadings averaged about 0.04 gr/dscf, which is equivalent to about 0.08 lb/MM Btu, when all of the individual measurements are averaged. The four ESP traverses averaged about the same as the average for all twelve individual values. However, the individual port traverses and measurements at individual points showed considerably more variability, with individual measurements ranging from as low as



0.02 gr/dscf to 0.08 gr/dscf. Since a wide range of variability was seen in repeat measurements at the same location, it is likely that the range of values measured is due to some temporal effect (e.g., whether or not a downstream field was wrapped during sample collection) rather than reflecting a significant bias among the various sampling locations.

#### **4.2.5.3 Flue Gas Halogen Species Concentrations**

During the baseline measurements conducted at Unit 3 in early October 2000, Method 26a sampling was employed to measure the concentrations of flue gas halogen species at the ESP B outlet location. Species measured included hydrochloric acid and chlorine, hydrofluoric acid and fluorine. The objective of making these measurements was to determine baseline concentrations of these species for comparison with measurements made during sorbent injection, to determine if any of these species would be effectively removed from the flue gas by the injected slurry sorbent. As mentioned above, corresponding measurements were not made during the short-term slurry injection tests, but will be made during the long-term test.

The results of these measurements are summarized in Tables 4-13 and 4-14. Flue gas concentration data in Table 4-13 show that the hydrochloric acid (HCl) concentration averaged about 36 ppm, while the hydrofluoric acid (HF) concentration averaged 14 ppm. Both of these values are in the typical range for bituminous coals. The chlorine (Cl<sub>2</sub>) and fluorine (F<sub>2</sub>) concentrations were measured to be much lower, at 0.6 ppm and 0.05 ppm, respectively. Again, both of these values are within the expected range.

Mass balance data in Table 4-14 show good agreement between the average measured flue gas chlorine species concentrations and the average of three coal chlorine measurements (samples for October 3, October 4, and October 6, 2000). The mass balance closed within approximately 2%. Only one coal sample was analyzed for fluorine content (the sample for October 4, 2000). The calculated mass balance closure for fluorine was not as close as the chlorine balance, closing within approximately 20%.

### **4.3 Summary and Conclusions**

A baseline test and three short-term (one- to two-week) slurry injection tests were conducted on one-half of Unit 3 of the Bruce Mansfield Plant, to determine the effectiveness of these sorbents injected into the furnace at controlling flue gas SO<sub>3</sub> concentrations as measured downstream of the ESP.

**Table 4-14. Summary of Method 26a Data**

Date	Test	Sample Gas Volume, dscf	Hydrogen Halides				Halogens			
			Chloride, mg/sample	Fluoride, mg/sample	HCl, ppmv (dry basis)	HF, ppmv (dry basis)	Chloride, mg/sample	Fluoride, mg/sample	Cl <sub>2</sub> , ppmv (dry basis)	F <sub>2</sub> , ppmv (dry basis)
10/03/00	1	68.16	111.6	33.5	39.2	21.9	3.20	0.090	0.56	0.03
10/03/00	2	66.09	104.3	18.9	37.8	12.8	1.77	0.065	0.32	0.02
10/04/00	3	66.82	107.8	14.0	38.6	9.4	1.85	0.068	0.33	0.02
10/05/00	4	71.14	101.6	22.6	34.2	14.2	2.51	0.388	0.42	0.12
10/05/00	5	68.86	97.8	21.7	34.0	14.1	2.94	0.221	0.51	0.07
10/05/00	6	70.59	89.3	20.8	30.3	13.2	8.44	0.192	1.43	0.06
Average	-	-	-	-	35.7	14.2	-	-	0.60	0.05

**Table 4-15. Hydrogen Halide and Halogen Mass Rates**

Date	Test	Hydrogen Halides		Halogens		Total		Fuel Data			
		HCl, lb/hr as Chloride	HF, lb/hr as Fluoride	Cl <sub>2</sub> , lb/hr as Chloride	F <sub>2</sub> , lb/hr as Fluoride	Chloride Emission, lb/hr	Fluoride Emission, lb/hr	Fuel Chloride Content, ug/g	Fuel Fluoride Content, ug/g	Approximate Input Rate of Chloride from Fuel, lb/hr	Approximate Input Rate of Fluoride from Fuel, lb/hr
10/03/00	1	347	104	9.9	0.3	357	104	560*	93**	323	54
10/03/00	2	334	61	5.7	0.2	340	61				
10/04/00	3	334	43	5.7	0.2	339	44				
10/05/00	4	306	68	7.6	1.2	314	69				
10/05/00	5	305	68	9.2	0.7	314	68				
10/05/00	6	271	63	26	0.6	297	64				
Average	-	316	68	11	0.5	327	68				

\*Average for samples collected 10/3/00, 10/4/00, and 10/6/00.

\*\*Value for coal sample collected 10/4/00.

Baseline testing on Unit 3 determined that about 1% of the coal sulfur is oxidized to  $\text{SO}_3$  rather than  $\text{SO}_2$  in the furnace and back pass of the boiler. This percent conversion was used along with the coal sulfur content in grab samples of coal feed, and one-half of the measured Unit 3 coal feed rates, to estimate the molar rate of formation of  $\text{SO}_3$  in Unit 3. This, in turn, was used to determine what slurry injection rate was required to achieve a desired sorbent-to- $\text{SO}_3$  mole ratio, or to calculate this mole ratio when injecting sorbent slurry at a given rate.

The first sorbent tested was pressure-hydrated dolomitic lime (PHDL). The PHDL was injected at molar ratios of calcium plus magnesium hydroxides-to- $\text{SO}_3$  in the furnace exit gas as high as 12:1. Even at the highest injection rate, the observed  $\text{SO}_3$  removal was limited to approximately 60% or less.

Previous literature data suggest that magnesium hydroxide injected into the furnace is much more reactive with flue gas  $\text{SO}_3$  than calcium hydroxide. If only the magnesium hydroxide content of the PHDL is considered, the highest Mg: $\text{SO}_3$  ratio tested was only 6:1. However, considering the weight of solids injected, the highest PHDL injection rate was equivalent to injecting commercial magnesium hydroxide at a Mg: $\text{SO}_3$  ratio of almost 14:1.

The PHDL injection was not observed to have a significant effect on ESP operation. This appears to be because high levels of  $\text{SO}_3$  removal were not achieved, and ample  $\text{SO}_3$  remained in the flue gas to condition the fly ash/sorbent mixture.

The second sorbent injected, commercial Mg, was able to achieve the target  $\text{SO}_3$  removal of 90% or greater. An injection rate equivalent to a Mg: $\text{SO}_3$  ratio in the range of 12:1 to 14:1 was able to lower the ESP B outlet  $\text{SO}_3$  concentrations to approximately 2 to 3 ppm. There was evidence that commercial Mg injected on the east side of the boiler was crossing over to the west flue gas path, which was not having sorbent injected, potentially diluting the sorbent effectiveness measured on the east side. It is very likely that when injecting sorbent into the entire furnace, lower Mg: $\text{SO}_3$  values will be effective at achieving high  $\text{SO}_3$  removal percentages than are described above.

Injecting at this rate, and lowering the ESP outlet  $\text{SO}_3$  concentrations to such a low value was observed to have an adverse effect on ESP operation, though. During the time period of high  $\text{SO}_3$  removal, the operating currents in the affected ESP were greatly reduced, and particulate emissions from that ESP were observed to increase by a factor of approximately four. This result suggests that it will not be possible to remove  $\text{SO}_3$  down to the 2 ppm level, as measured at the ESP outlet, and maintain acceptable ESP performance. It appears that an ESP outlet concentration of at least 5 ppm will be required to maintain ESP performance.

The third short-term slurry injection test evaluated a byproduct Mg sorbent produced from a Thioclear<sup>®</sup> FGD process at the Allegheny Energy Pleasants Station. This material was also capable of lowering the ESP outlet SO<sub>3</sub> concentrations on the side injected to 2 ppm, at a Mg:SO<sub>3</sub> ratio of about 7:1. Because the byproduct Mg is not pure magnesium hydroxide (it is about 62% magnesium hydroxide, with most of the balance being gypsum fines) the amount of solids injected at this molar ratio is about the same as when injecting the commercial Mg at a molar ratio of 11:1 to 12:1. However, for the Bruce Mansfield Plant, this material is advantageous for consideration because it could be produced onsite by lime addition to recover the liquid-phase magnesium in FGD blowdown liquor.

The byproduct Mg appeared to be more effective at SO<sub>3</sub> removal when it was injected higher in the furnace than the 11<sup>th</sup> floor level where the PHDL and commercial Mg were injected, and the byproduct Mg was initially injected. The results mentioned in the previous paragraph are for injection at the higher location, on the 14<sup>th</sup> floor of the boiler structure. The effect is most likely due to the furnace gas temperatures being lower at the 14<sup>th</sup> floor location, and less likely to cause dead burning of the calcined reagent (MgO).

This observation raises the issue of whether the first two sorbents would be more effective if they were injected at the higher location. However, the project budget did not allow retesting of the first two sorbents at the new injection level. Also, as mentioned above, the fact that the byproduct Mg could be produced on site make it the most favored reagent anyway.

As during the commercial Mg test, ESP operation was adversely affected when the outlet SO<sub>3</sub> concentrations were controlled down to 2 ppm. Comparing data when injecting at high sorbent rates on the 11<sup>th</sup> floor, where the SO<sub>3</sub> removal percentages were lower, to data when injecting at a 7:1 Mg:SO<sub>3</sub> ratio at the 14<sup>th</sup> floor, the effect appears to be from lowered SO<sub>3</sub> concentrations and not from the sorbent per se. That is, when injecting similar quantities on the 11<sup>th</sup> floor, where the ESP outlet SO<sub>3</sub> concentrations remained well above 2 ppm, no adverse effect on ESP performance was noted. To maintain acceptable ESP operation, it appears that ESP outlet SO<sub>3</sub> concentrations will have to be maintained at approximately 5 ppm or greater.

Based on these short-term test results, the byproduct Mg is recommended for further testing on the whole boiler, and for a longer test duration of 25 to 30 days. Injecting on the whole boiler will allow more accurate measurement of the Mg:SO<sub>3</sub> mole ratio required to achieve high levels of SO<sub>3</sub> removal on an on-going basis. This longer-term test will also allow the effects of sorbent injection and high SO<sub>3</sub> removal efficiency on ESP performance to be quantified, and will allow an opportunity to measure impacts of the sorbent injection on the removal of other acid gas

species (HCl and HF) and gas-phase arsenic. The longer-term test will also allow an opportunity to screen the effects of sorbent injection on SCR catalyst coupons, and on slagging in the upper furnace.